Policy instrument design to reduce financing costs in renewable energy technology projects

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IEA - RENEWABLE ENERGY TECHNOLOGY DEPLOYMENT

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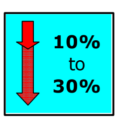
Summary

This report concerns the role of policies and policy instrument design in reducing the financing cost of renewable energy technology projects. What are key elements of successful policy schemes? What conditions should be set for successful design of future policies? What risk management measures can be included in policy schemes to mitigate or transfer risks away from investors and therewith reduce the cost of financing RES and can we apply this to other policy schemes in other countries?

These questions are answered by presenting the interactions of risks and policy design in general, and by considering the specific project finance case of four large-scale renewable energy project cases in more detail: a 20 MWe onshore wind energy project, a 100 MWe offshore wind energy project, a 0.5 MWe solar photovoltaic energy plant, and a 10 MWe / 26 MWth biomass co-generation plant. Their financial performance was evaluated under different representative policy support schemes (Germany, France, Netherlands, United Kingdom, California, and Québec).

Good policy instrument design can reduce the cost of renewable electricity by 10 to 30%.



Ensure long-term commitment towards renewable energy

Before looking at the exact design of the various elements in the support schemes, a clear political and societal long-term commitment towards renewable energy is required. Based on this, a stable and reliable support mechanism can be designed, that effectively meets the policy goal, at acceptable levels of investor risk, and at acceptable social costs. Commitment, stability, reliability and predictability are all elements that increase confidence of market actors, reduce regulatory risks, and hence significantly reduce cost of capital. A proper translation of this commitment in the design and timeframe of the support instruments, is the key challenge in this respect.

This effect can be significant: as compared to a support scheme with no particular attention to risk mitigation, the levelised cost of electricity can be reduced by 10 to 30%, with different values for different technologies. Countries with feed-in tariff schemes (Germany, France, and tender procedures in California and Québec) are believed to have already realised a significant part of this reduction potential for on- and offshore wind energy and solar photovoltaic energy (e.g. more than 20%).

5% to 20%

Remove risks by removing barriers

Policies that improve the success rate of the project development phase will reduce the project investment and hence levelised energy costs of renewable energy technologies. This refers to amongst others:

- improve permitting procedures (e.g. pre-planning, streamlining and simplification of procedures, one-stop agencies, maximum response periods), and
- improve grid connection procedures (e.g. technical and operational standards, transparent procedures, non-discriminatory access).

The overall effect on the cost of capital of removing barriers is hard to quantify. The direct effect on the levelised cost of electricity can be in the range of 5 to 10% due to increased project cost. But a poor development climate will also result in a higher required return on equity, which could result in a cost increase of the same order of magnitude.

5% to 15%

Remove risk by sharing risk

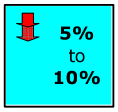
Although not encountered in the case studies, the following instruments can significantly reduce the cost of capital:

- Government loan guarantees
  By underwriting all or part of the debt for a project, lenders have significant lower risk in case of default or underperformance of the project. This risk reduction is translated in lower interest rates (e.g. 1-2%, resulting in reductions upto 5-10% in the levelised cost of electricity), but potentially also in longer debt terms and more favourable debt service requirements with even higher reductions in the cost of capital.
- Government project participation and/or investments in infrastructure
  Government project participation, for instance by investing in large-scale electrical infrastructure solutions for offshore wind energy, can reduce levelised cost of electricity by for instance 15% or more (with about one third as a direct effect of a reduction in the cost of capital).

Investment subsidies: for demonstration and market introduction

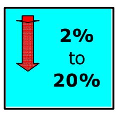
Investment subsidies are believed to be more effective at the demonstration and market introduction phase, than during the deployment phase with a larger emphasis on stimulating production of renewable energy. Investment grants could be converted in equity (government participation) or debt after successful commissioning of a project. Doing so the effect on the government budget can be kept to a minimum.

Debt measures: provide low interest loans and align the debt term with the technical lifetime



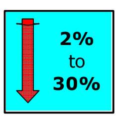
Policies that anticipate on risk assessment practices by lenders can reduce costs of capital significantly by creating market conditions and designing support schemes that result in debt terms being close to technical lifetimes (e.g. longer duration of production support and power purchase agreements (PPAs)). Low-interest loans, with discounts on interest rate that are typically in the range of 1-2%, can contribute to this. The direct overall effect of these kind of debt schemes is upto 5-10% on levelised cost of electricity. But indirectly they can affect other key financial parameters used by investors and other lenders, such as the economic lifetime, debt term and debt service conditions. The alignment of the debt period in the German low-interest government loan (e.g. KfW Umwelt Program) with the period of the feed-in tariff scheme, both contribute to significantly lower cost of capital.

Fiscal measures



Fiscal measures can have a significant impact on the levelised cost of electricity of a project. Investment tax deduction, production tax deduction, and flexible or accelerated depreciation schemes reduce levelised cost of electricity from several percent upto 10-20% in the examined cases. Not all projects and finance models will be able to reap the tax benefits of these schemes. A critical issue is the dependency on policies as the fiscal measures result in lower tax income.

Production support



An improved design of current production support schemes, and notably a good alignment with other support policies, can result in additional cost reductions in the range of 2-30%. The high end concerns projects with relative high project risk, such as offshore wind energy or biomass co-generation. For onshore wind energy, these potential improvements are smaller (several percentages to 10-15%), notably for some feed-in tariff and -premium schemes.

Feed-in tariff (FIT) and -premium (FIP) schemes: The most important element of FIP and FIT schemes is that they fully (FIT) or partially (FIP) remove the market risks of a project during a fixed period of time. The longer this period of guaranteed prices, the lower the cost of capital. Because of this, FIT/FIP have in general a relatively large debt schare. For the technologies considered in this report a timeframe of 15 to 20 years is preferred. In feed-in premium schemes the risk of variations in electricity market prices is reflected by a premium in the tariff in the purchase power agreement. It may be hard to acquire a PPA with the same 15 to 20 year tenure at reasonable risk premium levels.

Other production incentives: In some schemes a certain production incentive is given for each unit of renewable electricity produced over a given period of time (e.g. 10 CAN$/MWh over 10 year, in the EcoENERGY for Renewable Power in Canada). This production incentive is not intended to fully bridge the gap between electricity market prices and the price of renewable electricity, but apart from generating additional revenues, it contributes to removing part of the market risks for a project.

Tendering schemes: The tendering schemes discussed in this report (Québec, California) all result in guaranteed project-specific contract prices for a specific period of time. The tendering process is used to let the market determine what the required level of support should be. After winning the tender, a project developer has certainty about his operating income and can use and negotiate favourable financing terms. The project development phase has higher risks, as not all bids will be successful.

Obligation schemes: The cost of capital will generally be higher for obligation schemes due to both higher market risks and perceived regulatory risks. The certificate market - by its design - can not offer a fixed price directly as is the case in FIT/FIP schemes. Furthermore, the level and timeframe of the obligation as well as other key design parameters (e.g. penalties, issuing of certificates), are set by government policies and hence susceptible to policy changes. This results in lower contract periods in the PPA, lower debt terms and higher debt reserve conditions, or, in other words, in a higher levelised cost of electricity.

Reducing the cost of capital in quota obligation schemes can be achieved via various routes, but is not as easily done as with FIT and FIP schemes. A strong government commitment towards the scheme is essential in this respect. Changes in the scheme can seriously affect the continuity of existing projects and have to be applied with specific care. Increasing the economic lifetime, the contract period in the PPA, and the debt maturity will reduce the cost of capital. This could be achieved via the instruments discussed above: by seting favourable conditions in loan guarantees, (low-interest) government loans and/or government participation. The government can also oblige obligated parties to offer long-term contracts. This will be reflected in a risk premium, but – provided that a competitive market is functioning – this premium can be minimised. The main advantage is that the financing cost will be reduced due to the increased security.

General observations

Continuously improve the policy design
Policies that reduce the required return on equity by investors potentially have significant cost reduction implications. Improved design of existing policy support schemes may be more effective in this respect, than a switch to a different policy scheme. Reducing the required return on equity encompasses a wide range of measures that create stability and predictability of markets, amongst others:

- (i) long-term and sufficiently ambitious targets should be set,
- (ii) the policy instrument should remain active long enough to provide stable planning horizons and for a given project, the support scheme should not change during its lifetime,
- (iii) stop-and go policies are not suitable and a country's 'track record' in renewable energy policies probably influences perceived stability very much.

Keep the financing of the support scheme outside the government budget
In general, it is recommended that the financing of the support scheme is kept outside the government budget, especially when a country has a track record of multiple changes in policy design and/or allocation of budgets.

Anticipate for different financing models in the policy instrument design
In designing new policy instruments and schemes, the changing landscape of renewable energy financing solutions should be closely monitored and incorporated in this design. In designing support schemes, all market actors should be involved. Especially investment funds and banks will be able to provide feedback on the risks related to the design of these instruments.

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Annexes (separate document, available at www.iea-retd.org)

Annex 1: Country sheets

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Germany
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Italy
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Netherlands
Norway
Portugal
Spain
United Kingdom
USA

Annex 2: Ecofys cash flow model

1 Introduction

1.1 Scope of the report

Making investments comes with a cost: both investor and lender have financial criteria that have to be met, resulting in increased project costs as compared to a situation where capital is freely available. The assessment of the associated risk of a project has a major impact on this cost of capital. Higher (perceived) risks will result in applying more stringent criteria, and hence higher cost of capital.

As with all investments, investing in renewable energy technologies[1] (RES) is not without risk. Apart from possible inherent risks of the specific technology, the policy and social context can be perceived to be or actually be an important risk factor. Most RES still require policy support (both financial and regulatory) and when investors and lenders consider this support as inadequate, unreliable, or too risky in general, this will increase the cost of capital and thus the overall project cost. In turn, this might hinder the further deployment of renewable energy, or result in too high (societal) cost.

1.2 Objectives

This report concerns the role of policies and policy instrument design in reducing the financing cost of renewable energy technology projects. What are key elements of successful policy schemes? What conditions should be set for successful design of future policies? What risk management measures can be included in policy schemes to mitigate or transfer risks away from investors and therewith reduce the cost of financing RES and can we apply this to other policy schemes in other countries?

The objectives are to:

- identify design elements in policy instruments reducing perceived risks,
- give best practice examples of implemented international, national or regional policy designs reducing perceived risks, and
- make concrete recommendations for policy design.

[1] In this document renewable energy sources and technologies will be referred to as RES. RES-E refers to production of renewable electricity, RES-H to heat, and RES-F to fuels.

These objectives will be met by presenting the interactions of risks and policy design in general, and by considering the specific project finance of four large-scale RES project cases in more detail:

- a 20 MWe onshore wind energy project,
- a 100 MWe offshore wind energy project,
- a 0.5 MWe solar photovoltaic energy plant, and
- a 10 MWe biomass co-generation plant.

Their financial performance will be evaluated under different representative policy support schemes (Germany, France, Netherlands, United Kingdom, California, and Québec). This should generate more detailed insight in the interplay of the various elements of these support schemes, and contribute to the formulation of more generic recommendations.

1.3 Report structure

The report has the following outline:

- Financing risks of renewable energy projects (chapter 2)
  Introduction to the key elements that contribute to risk and uncertainty in financing RES. This introduction will frame the subsequent assessment and discussion of policies.
- Overview of policies and measures in selected IEA countries (chapter 3 and Annex 1)
  Which policy schemes and instruments have been implemented? What are key uncertainties and risks with respect to financing? What are key success factors that reduce financing cost? What generic lessons can be learned for other policy schemes?
- Analysis of selected policies and measures with respect to the cost of finance (chapter 4 and 5)
  What can be learned from a more detailed analysis of a selected set of policy instruments? What are specific risks and uncertainties and how can they be mitigated? What specific lessons can be learned for other policy schemes?
- Conclusions and recommendations: Options for policy designs that reduce the financing cost for RES, including opportunities of coordinating internationally different support policies (chapter 6)
  What recommendations can be made regarding policy designs that reduce the financing cost for RES?

2 Financing risks of renewable energy projects

This chapter will discuss the risks that affect renewable energy projects, their effect on financial variables and overall cost of capital.

2.1 Policies affect cost

There is no straight cause-and-effect chain that perfectly describes how policies affect the cost of renewable energy. However, the following model helps to illustrate several elements that are of importance to the development of renewable energy technologies that currently can not compete with conventional energy conversion technologies on existing markets (see Figure 2-1). In the next section we will provide more detail for each phase of the project cycle.

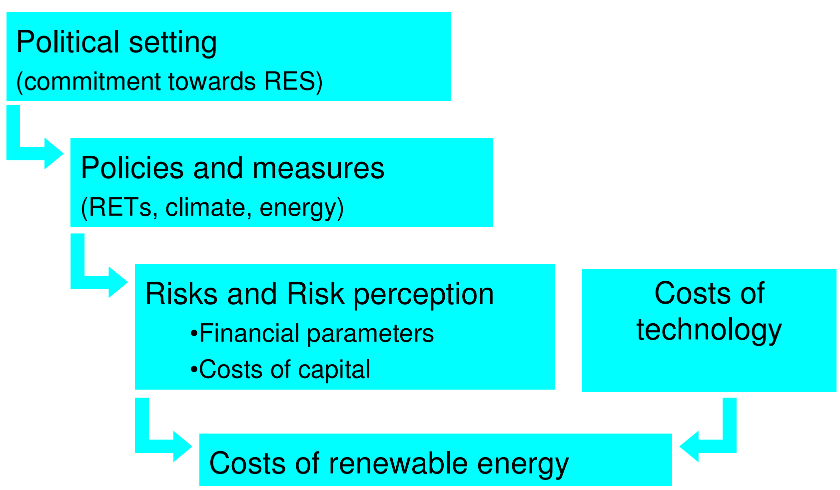

Figure 2-1 Policies affect costs of renewable energy

It starts with the political setting: is there commitment towards renewables and if so, how is this being substantiated? RES can contribute to the security and reliability of the energy supply system, reduce emissions of greenhouse gases and other air-pollutants, enforce the position of national industries and create jobs, and so on. What is the key driver? And is this commitment felt by all actors in society or only by a restricted group? E.g. on a national versus regional or municipal institutional level, in one or all government departments, by energy companies, by society and its individual citizens, et cetera.

In cases where there is some kind of political commitment, this may be substantiated in policies and measures. This could be in the form of concrete objectives for the share of RES in total energy consumption or for the total installed capacity of RES, via financial support schemes, dedicated standards or legislation, energy market restructuring, or in dedicated administrative procedures. In general, the policies and measures aim to reduce or eliminate the main barriers that RES are confronted with, such as perceived higher costs, or licensing issues.

Project developers, equity investors and debt lenders will assess the technical and financial performance of a RES project. In this assessment they will incorporate both the specific risks associated with the technology, and risks associated with the policy context. This is being translated in the specific financial terms that are being applied in the project financing. Higher risks will result in higher cost of capital and hence higher project costs and resulting energy costs. Policies and measures that reduce (regulatory) risks, generally reduce the (societal) cost of renewable energy.

2.2 Risk classes

In this section we will briefly present the risks associated with renewable energy technology projects, both in general terms and related to the phase in the project cycle. In general we can talk about six levels of risk which can affect the cost of capital for a project[1]:

- **Project level risk**
  Project level risk concerns the risk that is specific to the selected technology and project, notably during the construction and operation phase. This risk level will be discussed in more detail in the next section for each project phase.

- **Regulatory risk**
  Regulatory or institutional risk concerns the risk of adverse changes in the policy context discussed earlier. Policies and measures might change during the project cycle which may have significant impacts on the profitability of a project. Examples are changes to or even ending of policy support schemes or changes to the market design. As most markets for renewables are being regulated under policy schemes, this risk is of particular importance to renewable energy technologies.

[1] There are other risk elements that can affect the success and profitability of a project. Within the scope of this report they are not - or less - important.

- **Financial risk and Market risk**
  Financial risk relates to the risk of adverse changes in financial and/or economic parameters, such as interbank offered interest rates (e.g. EURIBOR, LIBOR, TIBOR) which are the basis for interest rates offered to the market, currency exchange rates, and inflation rates. Market risk concerns variations in prices of commodities, such as prices of biomass and electricity market prices.

- **Legal risk**
  The legal system of a country forms the basis of agreements and contracts between parties. The legal risk comprises the risk that enforcement of these contract obligations is not completely ensured by the legal system.

- **(Geo)Political risk**
  The political risk concerns the risk of major changes in key economic areas, such as a change in foreign-exchange rates by a central bank (sovereign risk).

- **Force Majeure risk**
  Force Majeure risk concerns the risk of any natural catastrophes (e.g. extreme weather, flooding) or human induced calamities (e.g. war or strike).

Project level risk and **regulatory risk** are of particular relevance to the deployment of RES, with a significant role for policies. Financial or market risk may be important as well, but the mechanisms are similar to or the same as for conventional energy projects. The remaining risk categories are less important for RES in most OECD countries. The weight given to each risk category differs for each technology, country or even region.

A wide range of instruments is available to transfer these risks to other parties which can help to reduce the overall cost of capital or to make the project bankable. Contracts with equipment suppliers or with service companies including performance guarantees over the project lifetime are an example. Furthermore, insurances and other financial derivatives are available to reduce risks for both investor and lender to the project.

2.3 Risks and the project cycle

The project cycle of the large-scale renewable energy projects that are covered in this report, generally have the (simplified) structure as depicted in Figure 2-2. Each phase has its own risks, risk management opportunities and sensitivity for policy changes.

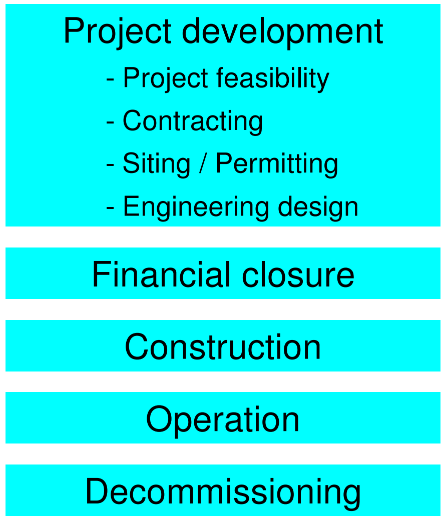

Figure 2-2 Typical project cycle for renewable energy technologies

2.3.1 Project development and financial closure

Project development covers a range of activities that are required to realise a financial closure of the project. It encompasses the assessment of the technical and institutional feasibility, preparation of contracts with suppliers of equipment and services and with purchasers of the produced energy, acquisition of land, acquisition of various permits, and (pre-)engineering of the project. All of these elements have to be completed successfully in order to come to an investment decision.

This phase already may require significant investments, typically in the order of several percentages of total project cost. A project developer will hence assess the investment climate and weigh each of the risk factors in order to have a maximum chance of reaching financial closure. Typically the following risk factors will be assessed: What is the average lead time for this type of project (which could range from 1 to over 10 years)? Will it be possible to get a permit and a good power purchase agreement (PPA)? Will there be a financial support scheme when the project is ready for financial closure? Will the project be bankable after all, and under what conditions? What can be done to improve these conditions from the equity perspective?

An investor may be willing to take some risk as he will benefit from any upswings in project returns, but lenders are much more risk averse and will demand for several securities that ensure the payment of debt and interest. This is being translated in the financial parameters that lenders apply, such as debt term, interest rate, and debt service coverage ratio (see section 2.4). At the stage of financial closure, the risk assessment will concern the remaining phases of the project cycle only.

The following risks may be encountered during the project development phase[2]:

Project development phase towards financial closure	
Risks:	• Acquisition of permits is not successful. • Connection to the electricity grid is impossible or too expensive. • Energy purchase agreement is not reached or does not meet the conditions posed by lenders (e.g. the contract period is too short). • Delay in project development due to legal or institutional procedures, resulting in the project being not viable due to: - Higher costs of equipment and services - Unfavourable changes to or elimination of policy support schemes
Risk mitigation:	Providing information to stakeholders and/or offering the opportunity to participate in the project can increase the chance of acquiring permits.
Role of policies:	The role of policies is of crucial importance for the project development phase. The regulatory risk can be reduced by creating a stable and reliable policy framework, for instance by formulating long-term targets, with policy schemes that have sufficient long lifetimes. The political commitment towards RES needs to be embodied in the complete government organisation. If legal and institutional procedures are geared to a smooth but responsible introduction of renewable energy technologies, the lead time and success rate of projects can be improved, resulting in a faster deployment at lower project costs. This asks for supportive legislation, a facilitating bureaucracy and a fair and transparent organisation of the (energy) markets. Investment subsidies and/or fiscal measures can contribute to the bankability of a project by reducing the debt leverage. By making energy resource data available to the market, more certainty in predicted energy yields can be provided to financers resulting in lower cost of capital. As an example: wind speed data could be made available to project developers.

[2] UNEP (2006, 2007ab), De Noord and Sambeek (2003) and Cleijne and Ruijgrok (2004)

Impact on costs:	The impact on overall project costs can be significant. Delays in the project development phase can increase total project costs even above 10%, in cases with long legal procedures under changing market conditions. The market value of projects that successfully have completed the development phase can be high in a context where only few project initiatives reach this stage, after longer average lead times. This results in higher overall project costs. The impact on the cost of capital is medium, as the cost of capital at this stage is mainly determined by the risks of the subsequent phases.
Specific to RES:	Given the major impact of policies on the success rate of the project development phase, this is very specific to RES.

2.3.2 Construction

The construction phase concerns the actual construction of the project, usually by several subcontractors, either subcontracted individually or as a consortium. The construction phase has several risks with potentially high impacts, which are generally not specific to renewable energy projects. It concerns for example cost and/or time overruns which negatively affect the cash flow of the project. Another risk is that subcontractors or suppliers are not able to meet the agreed technical specifications or underperform in other ways. Several generic risk mitigation strategies can be applied, such as insurances and specific contract conditions. The role of policies in reducing the risk during the construction phase is limited, as all permits should have been acquired in the project development phase. However, for new technologies that not yet have an institutional track-record, new institutional barriers might occur during construction. Some governments provide (export) credit facilities to suppliers in order to remove the risk of non-compliance by the supplier due to financial constraints. The perceived effectiveness of the risk mitigation measures is a crucial element in the determination of the financial parameters that are being applied by investors and lenders to the project.

Construction phase	
Risks:	Construction risk - Time and/or cost overrun - Technical specifications are not met - Assumptions prove to be not realistic Counterparty risk - Construction contractor does not perform as per contract

Risk mitigation:	• Insurance • Turnkey contract • Performance guarantees • Liquidated damages on non-performance • Due diligence process for subcontractors and suppliers
Role of policies:	Limited. Some government reduce risks for project investors by providing credit facilities to suppliers.
Impact on costs:	High, given the potential high impact on the cash flow of the project.
Specific to RES:	The risks of this phase are in general not specific to renewable energy technologies. However, some technologies might be more sensitive for particular incidents. For example construction of offshore wind energy projects might suffer delays from (severe) weather conditions.

2.3.3 Operation

During the operation phase the project will have to generate the net positive cash flow that should provide the required return on equity after payment of debt services and taxes. In renewable energy projects the main contribution to the positive cash flow comes from energy sales. Any disturbance in the production of energy (electricity and/or heat, or fuels) will result in lower income and potentially liquidation of the project. As can be seen from the listing below, several risk types are relevant to the operation phase.

Operation phase	
Risks:	Performance risk - Underperformance of installation - Underperformance of operation and maintenance (O&M) - Theft / damage Resource risk (incl. fuel supply) - Variable availability of resource (e.g. windspeed profile or solar irradiation) - Disturbance in logistics of biomass supply Market risk - Demand risk (uncompetitive pricing policy of renewable energy projects) - Price risk (changes in market prices of energy carriers and/or certificates for climate change abatement or renewable energy production) Regulatory risk - Design of policy support scheme - General support scheme is modified, directly or indirectly affecting the

	cash flow of the project Credit risk Counterparty risk (e.g. of subcontractor responsible for operation and maintenance (O&M))
Risk mitigation:	Performance risk - Outsourcing of O&M: e.g. to same EPC (Engineering, Procurement and Construction) contractor, incorporating incentives to perform optimally - Equipment warranties - Insurances Resource risk - Insurances, e.g. weather insurance and weather derivatives for wind energy projects - Long-term biomass supply contracts - Multi-fuel input concepts for bioenergy projects - Biomass storage Market risk - Long-term power purchase agreements (PPA) - Long-term contracts for renewable energy certificates
Role of policies:	Policies can help to reduce the regulatory and market risks for a project, by optimising the following parameters: • Design of renewable energy policies and/or targets • Design of support schemes (e.g. feed-in, feed-in premium, quota) • Stability of policy context • Energy market design • Role of transmission system operator (TSO) • Role of regulator
Impact on costs:	The impact on costs and cost of finance are high (see section 2.4.3).
Specific to RES:	Given the important role of policy support schemes during the operation phase, this is very specific to the deployment of RES.

The risk profile of the operation phase is again a crucial element in the determination of the financial parameters at financial closure. Several generic and RES-specific risk mitigation strategies can be applied, which reduce risks or remove them from the project. Examples are weather insurances or weather derivates. Apart from the effectiveness of the risk mitigation measures, the design and perceived stability of the policy support scheme is a key parameter (this is illustrated in section 3.1).

2.3.4 Decommissioning

The risks of the decommissioning phase are in general low as in many cases the scrap value of the installation is higher than the decommissioning costs. In many cases national regulations ask for the creation of some kind of decommissioning fund, which should be filled during the operation phase or at the beginning of the project.

Decommissioning phase	
Risks:	No budget available
Risk mitigation:	Decommissioning fund
Role of policies:	Create level playing field for RES and other technologies (e.g. no difference in procedures for decommissioning funds)
Impact on costs:	Low
Specific to RES:	No

2.3.5 Conclusion

As illustrated above, the **project development phase** and **operation phase** have significant risks that are or can be affected by policies, and hence have significant impact on project cost and cost of finance. Policies affecting the project development phase have notably impact on the project cost and market value of the project, and to some extent on the financing cost. The policy and market context of the operation phase are crucial for the financing cost. In the next chapters we will present the policy schemes of selected IEA countries in more detail, and point at the key policy design parameters that can reduce risks and hence financing cost.

2.4 Financing renewable energy projects

In the previous section we've illustrated how policies affect risk. In this section we will illustrate how risk affects financial parameters and hence financing cost of RES. In the next chapters an overview will be given of several support schemes in place, and the abovementioned relation between policies and financing cost will be assessed in more detail, but first the key elements and sensitivities of financing renewable energy projects will be presented. As a start, it is good to understand how and by whom RES can be financed. The following types of capital typically can be used to finance a project: loans (debt), equity, and investment grants (subsidy).

A loan or debt is the amount of money that is provided to the project by a third party under the condition that this will be (entirely or partially) repaid during or at the end of the agreed debt term. Furthermore, interest has to be paid at regular intervals over the amount of money that is borrowed. Loans are typically provided by banks, but also individuals or organisations can directly or indirectly (via funds) act as lenders. There are many types of loans, each differently incorporating and securing (perceived) risk, such as senior debt, junior or subordinate debt, or lease finance.

Equity is capital from investors or shareholders that receive dividends from the project in regular intervals (from the so-called free cash flow, the profits after debt service of both senior and junior debt, and after tax payment). The accumulation of dividends over the lifetime of the project should significantly outweigh the initial investment in order to be attractive for investors. The risk for equity providers is much higher than for lenders, resulting in higher costs of finance expressed in the required return on equity (RoE, after tax) being much higher than the interest rate asked by lenders. Equity can be provided by different type of investors, such as individuals or companies providing their own capital, private equity funds, venture capital funds, and shareholders that acquire shares via stock markets. Each have their own risk strategies and will hence apply their own criteria for return on investment.

Often projects are financed with so-called mezzanine capital (or mezzanine debt), which is a hybrid form of finance incorporating a wide variety of both debt and equity arrangements. Typically mezzanine finance will consist of a subordinated debt with additional securities, preference shares, or convertible bonds.

Investment grants (or subsidies), typically provided by governmental organisations, do not need to be repaid and require no payment of dividends. Grants are typically provided to projects that are not commercially feasible or bankable. Sometimes the conditions of the grant may involve conversion into debt or equity in case of commercial success.

There are different financing models that can be used: project finance and corporate (on-balance sheet) finance being the most predominant. But several other models can be used, such as lease financing. Within this study we will concentrate on project finance. For large RES projects with investments ranging from several tens to hundreds of million euros, the project initiator often has not enough capital available to finance the project on its balance sheet and therefore project finance is used.

2.4.1 Project finance

In project finance, the cash flow of the project itself determines the structure of the financing model and its key financial parameters. In this section we will illustrate this using an example of a 20 MW onshore wind project in an arbitrary country with no particular support scheme. Assumptions on the key technical, cost, fiscal and financial parameters are given in Table 2-1. The technical parameters determine the total annual energy production and hence the positive cash flow into the project that can be attained by selling the electricity to the market and/or by acquiring production related fees from RES support schemes. The negative cash flow is mainly determined by the operation cost and preventive and reconstructive maintenance cost, the debt service to lenders (i.e. interest and amortization of the debt), and tax payments.

Table 2-1 Simplified project parameters of a typical 20 MW onshore wind project in an arbitrary country with no support scheme for renewable energy

Technical parameters		
Capacity	20	MW
Full load hours	2000	h
Technical lifetime	15	yr
Cost parameters		
Investment	22	M€
Operation & Maintenance	0.8	M€/yr
Inflation rate[a]	0	%/yr
Power purchase agreement		
Electricity tariff	50	€/MWh
PPA term	10	yr
Fiscal parameters		
Corporate tax	30	%
Tax loss carry-forward	no	
Depreciation type	linear (10 yr)	

Financing parameters		
Equity parameters		
- Equity share[b]	25	%
- Return on equity (RoE)	15	%
- Equity term	15	yr
Debt parameters (annuity)		
- Debt share[b]	75	%
- Interest rate	6	%/yr
- Debt term	10	yr
- Debt Service Coverage Ratio[c]	1.35	
WACC[d]	6.9	%
Nominal levelised cost (15 yr)	96	€/MWh

[a] In this example, with the inflation rate set at 0%/yr, nominal costs equal real costs.

[b] The shares of equity and debt are the result of on optimisation routine in the cash flow analysis. At this equity/debt ratio levelised costs are at a minimum, while total project costs have a net present value of zero, and the minimum debt service coverage ratio condition is fulfilled.

[c] Annually constrained.

[d] WACC: Weighted Average Cost of Capital

$$WACC = \left[\frac{E}{D+E}\right] * R_e + \left[\frac{D}{D+E}\right] * (1 - Corporate\ tax) * R_d$$

with E : Equity share; D : Debt share; R_e : Return on Equity (after tax); R_d : Debt interest rate

The data of Table 2-1 are used as input to a generic cash flow model (see Annex 2), in essence similar to the one described by Wiser and Kahn (1996)[3]. The cash flow model incorporates all relevant technical, economic and fiscal variables, and allows for a sophisticated analysis of different policy schemes and technologies[4]. If the net present value of the free cash flow over the project lifetime is larger than or equal to zero, valued against the return on equity required by the investor, the project basically is viable from the equity perspective. However, in cases where part of the project investment cost is to be covered by debts, the lenders (typically banks) will ask for securities to minimise risks during the operation phase of the project. As discussed in the previous section, several risk mitigation strategies can be applied to satisfy the demands of the lender. But in the end, the lender will lend money against financing conditions that further reduce the risk of non-compliance by the project. Elements of these conditions are the debt term, the debt interest rate and the minimum required debt service coverage ratio (DSCR)[5].

The DSCR is the total net operating income divided by the debt service. If DSCR equals unity, all net operating income is used for repayment of interest and amortization, provided that the project exactly performs as described in the business plan. Hence, lenders ask for a DSCR larger than unity, in order to ensure fulfilment of the debt service in cases where the project performs less than projected, for instance due to lower actual wind speeds or reconstructive maintenance. For renewable energy projects, the DSCR typically ranges from 1.3 to 2, depending on the maturity of the technology and other risk factors. If the net operating income of the project is too low to meet the DSCR requirements, the size of the debt fraction has to be reduced and more equity is required.

The nominal levelised cost of electricity presented in Table 2-1, is the minimum price of the generated electricity that would be required to make the project viable from the equity perspective (net present value of free cash flow ≥ 0) and bankable from the lenders perspective (DSCR ≥ 1.35 in this particular example). This price (including an electricity price growth rate (here taken as 0%/year)) is assumed to be paid for the electricity over the full economic lifetime of the project. Because of the debt service requirements, there is a direct relation with the debt/equity ratio, as illustrated in Figure 2-3. In this particular example the optimum is at about 25% equity. At higher rates, the levelised cost increases as the cost of equity is higher than that of debt (15% versus 6% in this example). At lower rates, the minimum debt service requirement demands higher operating income and hence shows higher levelised cost. Figure 2-3 also illustrates the effect of applying different values for the DSCR. Higher DSCRs result in a shift towards higher equity shares and a

[3] Wiser and Kahn (1996)
[4] The Ecofys cash flow model for analysis of renewable energy projects has been developed since 1996. For a short description see Annex 2.
[5] Other debt service conditions are being used as well.

higher levelised cost of electricity. The DSCR determines the minimum levelised cost of electricity and the related equity share that can be attained. At higher equity shares, the DSCR can allways be met and is not constraining the debt/equity ratio.

In this example, the levelised cost at 25% equity is about 96 €/MWh for a period of 15 years, whereas the power purchase agreements in this example covers only an income of 50 €/MWh over a 10 year period. It is clear that without additional financial support this project will not be feasible.

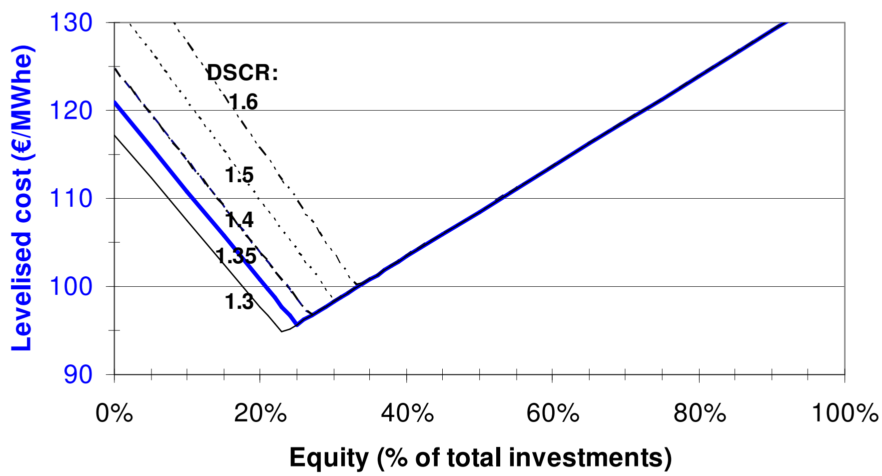

Figure 2-3 Levelised cost of electricity for the 20 MW onshore wind energy reference project: as a function of equity fraction, and debt service coverage requirement (DSCR)

2.4.2 Corporate finance

For comparison we shortly address the case of corporate finance, where the project is financed on the balance sheet of a company. The main implication is that the financing of the project is based on the risk profile of the company as a whole, and not of the particular project. With larger, utility-like companies this usually results in lower risk factors and hence lower cost of capital: Debt rates and debt terms are generally more favourable, and the required return on equity by the company is often lower. Furthermore, there are no restrictions on the debt service of the particular project. This generally results in a reduction of the levelised cost of electricity. The design of both the general fiscal regime and the specific renewable energy support schemes in place, determine the overall difference in levelised cost of project versus corporate finance.

2.4.3 Sensitivity of renewable energy costs for changes in key financial parameters

Figure 2-4 illustrates the sensitivity of the levelised cost for changes in several financial parameters for the 20 MW wind energy reference project (with default parameters as presented in Table 2-1). Most of these parameters are directly related to risks and risk perception, and hence touch upon the core topic of this report: how can policies reduce risks and hence cost of capital?

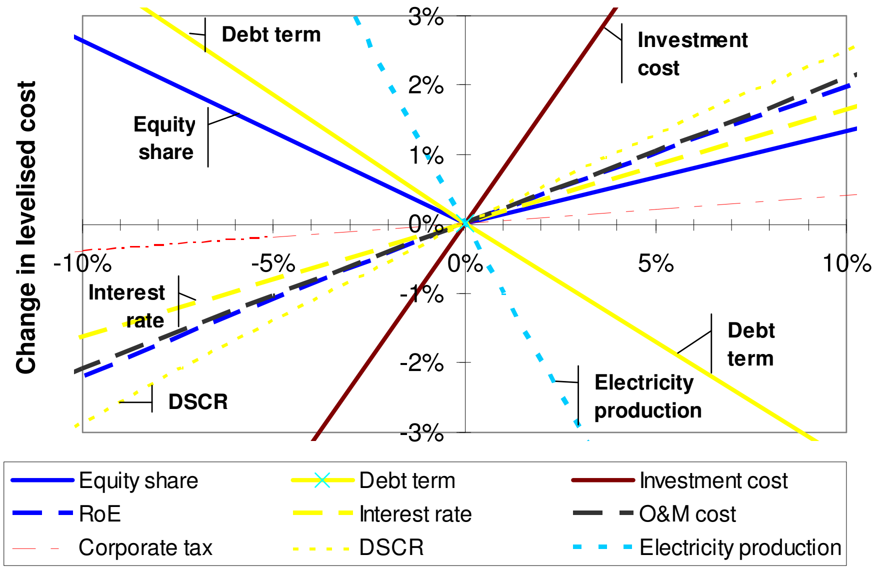

Figure 2-4 Sensitivity of nominal levelised cost of electricity (y-axis) for changes in key financial parameters (x-axis) for the 20 MW onshore wind energy reference project

Changes in electricity production and investment have the largest impact on levelised cost, followed by the operation and maintenance (O&M) cost, the key variables of the debt conditions and the required return on equity (RoE), which are directly related to project risks.

Investment and operation and maintenance (O&M) costs

Changes in investment and operation and maintenance costs have significant impacts on levelised cost. For bioenergy projects, with typically lower specific investment costs but higher operation costs due to fuel consumption, the importance of these O&M costs is even more prominent than shown here for the wind energy case.

As discussed before, investment costs are partly related to policies and measures via the success rate of project development. The lower this rate, the higher the market value of developed projects, which is translated in higher investment costs and/or higher required return on equity (see below). Impacts on levelised cost are significant. In this particular example a 10% higher investment results in an 8% higher levelised cost. At financial close the investment costs are known. During construction cost overruns might occur, but as indicated before several risk mitigation strategies can be applied to reduce the impact on overall project performance.

Operation and maintenance costs are generally less affected by policies. One exception concerns the use of biomass in bioenergy projects. Changes in policies affecting the key drivers of different biomass markets (e.g. for biofuels, electricity and/or heat, materials) will affect biomass prices and hence operation costs of these type of projects. This may concern changes in biomass sustainability criteria, targets for biofuels, and so on. This uncertainty will be reflected in the debt and equity parameters and hence contribute to a higher cost of capital.

Based on the above, the following generic statements can be made (see also OPTRES (2007)):

- Policies that improve the success rate of the project development phase will reduce the project investment and hence energy costs of renewable energy technologies. This refers to amongst others:
    - Improving permitting procedures (e.g. pre-planning, streamlining and simplification of procedures, one-stop agencies, maximum response periods)
    - Improving grid connection procedures (e.g. technical and operational standards, transparent procedures, non-discriminatory access)
- A stable and predictable long-term policy context will contribute to this improved success rate and reduce both investment cost and cost of capital.

Debt parameters

The key debt parameters are debt term, interest rate, minimum required debt service coverage ratio (DSCR), and debt share. Figure 2-5 shows the levelised cost of electricity and the equity share as a function of the former three parameters (see also Figure 2-3). The dependency is straightforward: higher debt terms, lower interest rates and lower debt service requirements will result in lower levelised cost.

In project finance the debt term is typically related to the terms of energy purchase contracts and/or support schemes, restricted by the technical lifetime of the technology but rarely larger than 15 year. Hence, energy market characteristics and renewable energy policies have a direct and strong impact on this parameter. In this particular example an extension of the debt term from 10 to 15 years will reduce levelised cost by 12%. It should be noted that (large) projects can often be refinanced after a period of satisfactory operation. With more uncertainties being eliminated (the project operates as expected, or even better) more favourable debt conditions can often be negotiated.

The interest rate that lenders negotiate with the project owners reflects many general economic conditions (such as interbank interest rates) as well as project related technical and situational aspects. This includes an assessment of the effectiveness of various risk mitigation measures (see section 2.3) and of the maturity of the renewable energy technology or the practices and technologies used for construction and operation of this technology (notably relevant for offshore wind or geothermal energy projects). If detailed site-specific resource and risk conditions are well known and understood, this will reduce cost of capital by improved debt conditions. For instance, the availability of wind speed data can reduce negotiated interest rates by several tens of percent points in particular cases. A reduction of the interest rate from 6% to 5% will result in cost reductions of about 3% in the current example.

The debt service coverage ratio shows a similar reflection of the risk-assessment by lenders as is the case for the interest rate. New, unproven technologies will generally encounter a higher DSCR value than proven technologies (typically 2 or higher). In our example, an increase in the DSCR from 1.35 to 2 will result in a cost increase of 10%. A reduction from 1.35 to 1.3 results in a cost reduction of 1%. If debt reserves can be created, annual DSCR constraints can be partly covered by banking the surplus of previous years. This increases the leverage of a project.

As discussed before, the equity/debt ratio is typically the result of finding the optimum configuration of financial parameters. In our (simplified) case this means achieving the highest return on investment, while at the same time meeting the debt service requirements, which is clearly shown in Figure 2-3. In actual project finance cases this optimisation will concern many more parameters.

A reduction in (perceived) risks typically affects more than one of the debt parameters at the same time. The combined effect of the above changes in debt parameters for the wind energy example (debt rate 5%, debt term 15 year, DSCR = 1.3) can be larger than the sum of the individual effects: the combined cost reduction as compared to the reference case (see Table 2-1) is about 16%.

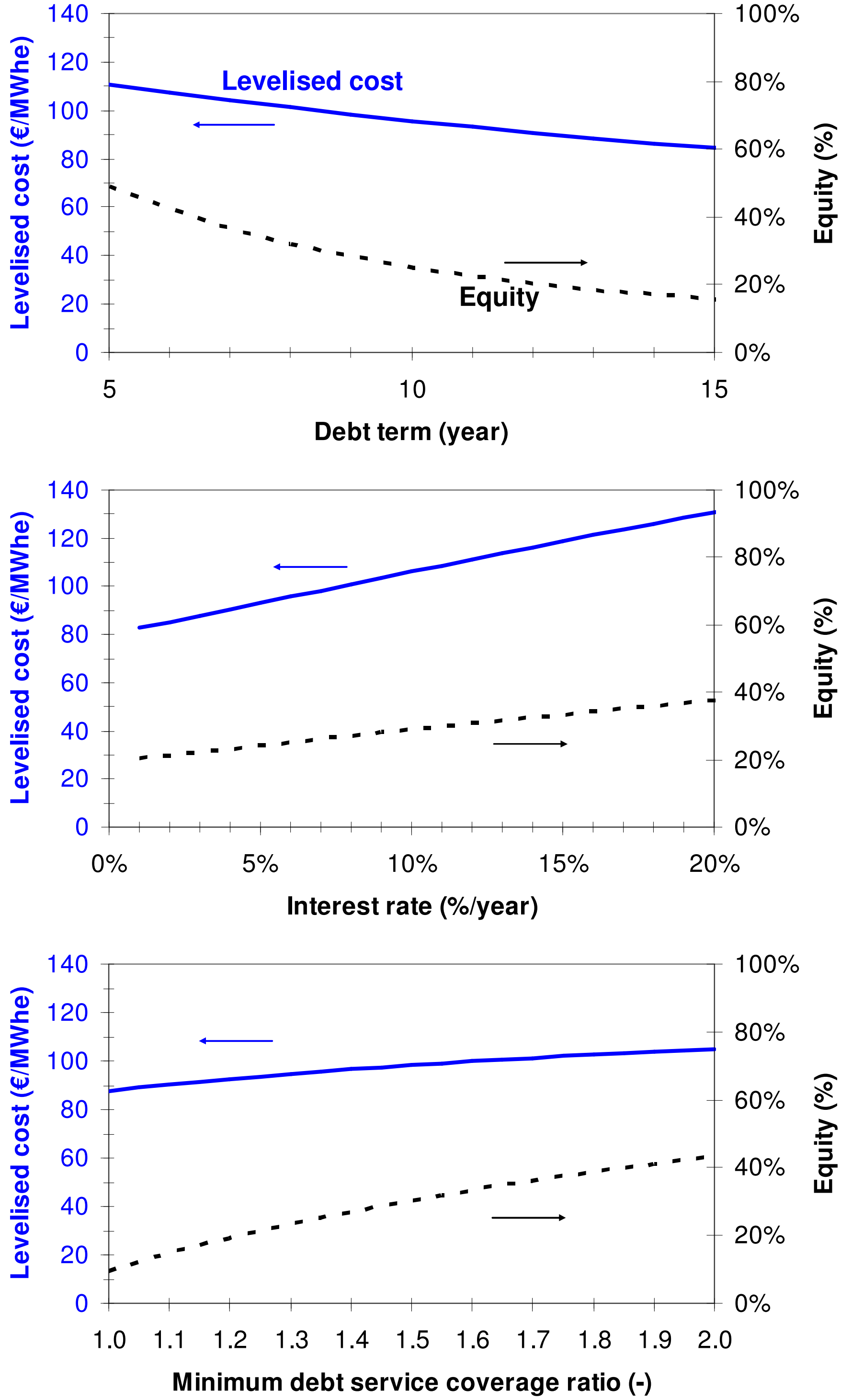

Figure 2-5 Levelised cost of electricity for the 20 MW onshore wind energy reference project: as a function of debt term (top), interest rate (middle), and debt service coverage ratio (bottom)

The policy implications can be summarised as follows:

Policies that anticipate on risk assessment practices by lenders can reduce costs of capital significantly:

- Create market conditions and design support schemes that result in debt terms being close to technical lifetimes (e.g. longer duration of production support and PPAs).
- For large investments in infrastructure (e.g. offshore electricity grids with technical lifetimes of components ranging from 20 to 40 year), this could imply investments by transmission system operators (TSOs) based on corporate finance at more favourable debt conditions (much longer term, lower interest rate due to lower risk, et cetera).
- Take measures that result in lower interest rates, e.g.:
  - offer low (state bank) interest rates
  - offer tax deductions for investments in renewable energy funds
  - facilitate the collection and disclosure of site-specific resource and other relevant data, such as meteorological, geological or bathymetric data (e.g. wind, solar, wave and tidal energy resource)
- Facilitate the demonstration of new technologies that will result in improved knowledge on the risk profiles of these technologies and hence reduce the debt service requirements and required return on equity for future projects.
- Reduce risks, e.g. by offering bank guarantees, or by participating as co-investor in projects.

Equity parameters

The most important equity parameters are the required return on equity after taxes (RoE) by the investor, and the equity share. As illustrated in Figure 2-3, the latter is closely related to the conditions of the lender, such as the debt service coverage ratio.

Figure 2-6 shows that a higher required return on equity results in a shift from equity to debt. In order to meet debt service requirements, the levelised cost needs to increase at the same time. If the required return on equity decreases from 15% to 10% the levelised cost declines by about 8% in this example.

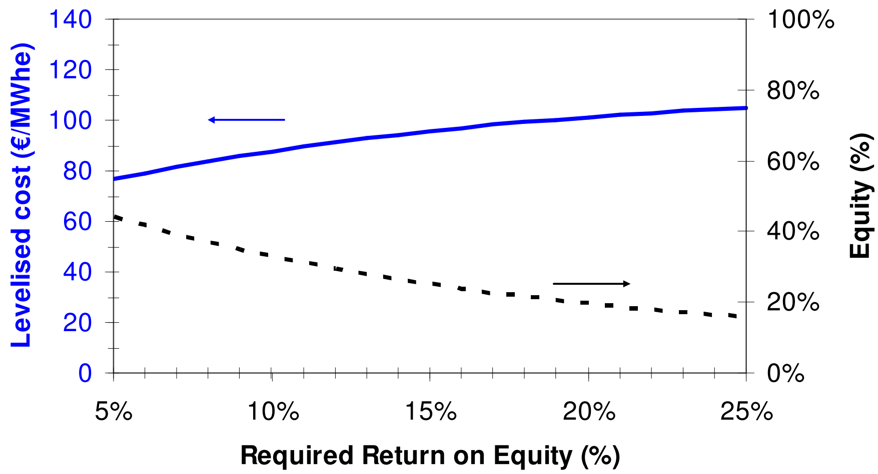

Figure 2-6 Levelised cost of electricity for the 20 MW onshore wind energy reference project: as a function of required return on equity

What value of the required return on equity is being used by equity providers? An investor can choose amongst different investments, with different profiles in terms of risk, maturity, and payment of dividend and return of principal. Dunlop (2006)[6] and stakeholders interviewed for this study state that large RES projects compete for capital with listed asset classes related to infrastructure (e.g. water supply, shipping, harbours, conventional electricity supply, real estate). These listed asset classes have similar financial characteristics as many RES projects, and typically have an internal rate of return (IRR) of about 7-9% (post-tax). The return on equity for RES projects is then typically the sum of[7]:

- a risk-free rate (e.g. 3-5% for 10 year government bonds);
- an equity risk premium related to the performance of similar listed asset classes as discussed above (e.g. a premium of 4-5% to compare with the IRR of 7-9%);
- in case the equity is provided via a fund, management fees add 2% or more to the equity rate, and an illiquidity premium of about 3% may be incorporated by the investor for the fact that the shares can not be sold as easily as stock exchange listed funds;
- a technology or "esoteric asset class" premium for new and unproven technologies or institutional situations (e.g. 3-15%); and
- a regulatory risk premium reflecting the risks of the energy markets and renewable energy support schemes (e.g. a -3% reduction for low-risk to +3% extra for schemes with higher risk).

[6] Dunlop (2006)
[7] Based on Dunlop (2006) but with updates for some variables.

Depending on the investment strategy of the equity provider (and the actual macro-economic parameters) the required return on equity will vary from about 12-15% for proven technologies (such as onshore wind energy) in markets with no additional regulatory risk. As mentioned, one of the aspects affecting the required return on equity is the regulatory context and the renewable energy support scheme in place.

Following a slightly different approach, the European Wind Energy Association[8] has derived estimates for the Weighted Average Cost of Capital (WACC) for renewable electricity projects in Europe under different support schemes. From this the required return on equity can be derived[9] which results in similar results, as shown in Figure 2-7.

The figure shows that the values are lowest for feed-in schemes, followed by feed-in premium and tendering schemes, obligation schemes with tradable green certificates, and finally investment subsidies. Furthermore, the figure shows that significant improvements can be achieved in designing more advanced schemes where several barriers are being removed. As discussed before, this has significant impact on the levelised cost of energy. The advanced schemes have the following elements: apply sufficient long periods of support (e.g. 10 to 20 year) in feed-in tariff (FIT) and –premium (FIP) schemes, use technology-specific tariffs/premiums or investment subsidies, allow for changes in cost structures (for new capacity), use stepped tariffs (FIT) for different resource categories (e.g. reflecting differences in wind classes), allow for longer term power purchase agreements (e.g. minimal 15 years in tender schemes), use clear tender procedures with deadlines and meaningful penalties, and long-term (> 20 year) mandatory targets for obligation schemes.

It should be emphasized that the RoE's depicted in Figure 2-7 are generic and will change over time depending on changes in general economic conditions, technologies, design and organisation of market, and design of policy schemes; and due to advanced experience with these schemes. Furthermore, the data are not technology specific, whereas in practice there will be a discrepancy between technologies.

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[8] EWEA (2005), note the calculations of the WACC in this EWEA report are not consistent with conventional WACC calculations

[9] Using the default values for interest rate, equity share and corporate tax as given in Table 2-1.

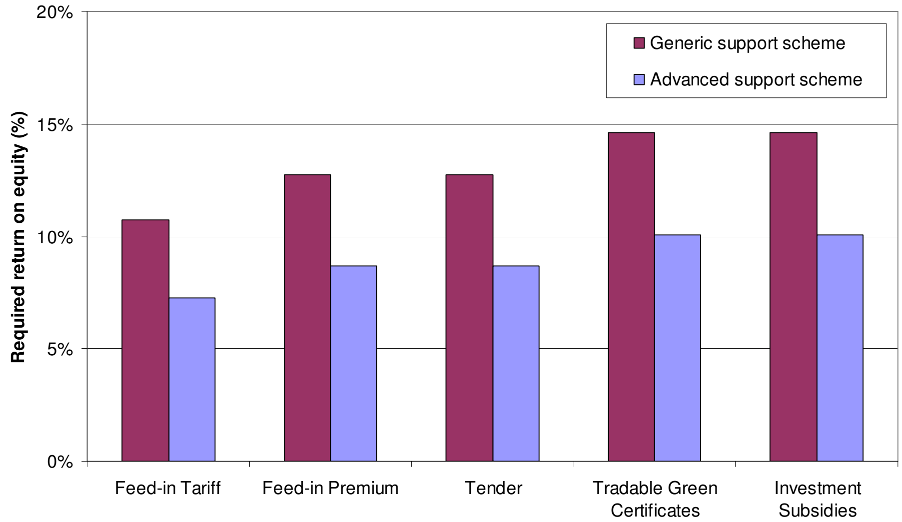

Figure 2-7 Required return on equity as a function of the renewable electricity support scheme, both for current generic schemes and more advanced schemes[8]

The policy implications can be summarised as follows:

- Policies that reduce the required return on equity by investors potentially have significant cost reduction implications.
- Improved design of existing policy support schemes may be more effective in this respect, than a switch to a different policy scheme.
- Reducing the required return on equity encompasses a wide range of measures that create stability and predictability of markets, amongst others:
    - long-term and sufficiently ambitious targets should be set
    - the policy instrument should remain active long enough to provide stable planning horizons and for a given project, the support scheme should not change during its lifetime
    - stop-and go policies are not suitable and a country's 'track record' in RES policies probably influences perceived stability very much

Tax parameters

The fiscal regime present in a country or region is important for the feasibility and bankability of a renewable energy project. Important factors are (amongst others) the corporate tax level, the applicable tax depreciation methods, and the amount of flexibility built in the tax system (e.g. with regards to accounting practices regarding loss carry-back or carry-forward).

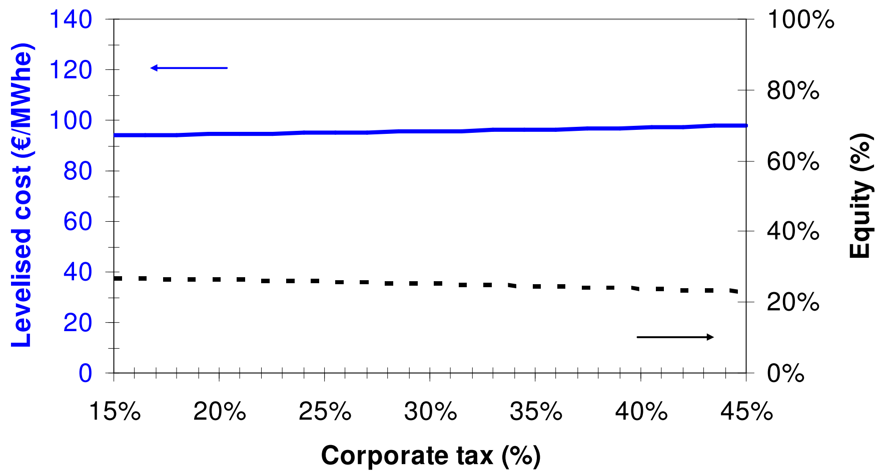

Figure 2-8 Levelised cost of electricity for the 20 MW onshore wind energy reference project: as a function of corporate tax levels (linear fiscal depreciation over 10 year)

Corporate taxes vary around the world, from 0% in the Cayman Islands to 55% and even more for foreign investors in oil projects in the United Arab Emirates. However, most countries have tax levels within the range of 15% to 40%[10]. As can be seen from Figure 2-8, changes in corporate tax levels only have a limited effect on the levelised cost of electricity: a reduction from 30% to 20% results in a cost reduction of about 1% in the considered example.

More important are the accounting rules that are used to depreciate the asset over its fiscal lifetime. Figure 2-9 depicts different asset depreciation methods for a project with a residual value of 10% at the end of the depreciation period (default chosen as 10 year):

- the linear or straight line depreciation (a fixed percentage per year)
- the sum-of-years depreciation (highest depreciation in the first years)
- the single and double declining balance depreciation, with and without a switch to straight line depreciation if this is larger than the depreciation under declining balance
- Modified Accelerated Cost Recovery System (MACRS) over 5 and 15 years (here depicted according to the half-year convention), as used in the United States of America

[10] KPMG International (2006) and Eurostat (2007)

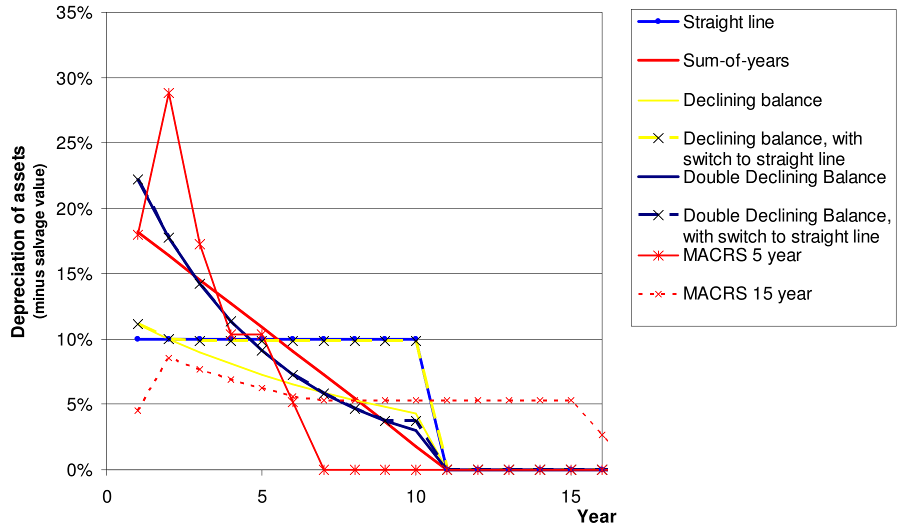

Figure 2-9 Example of fiscal depreciation of assets under different methods, relative to the book value at the start of project (residual value at the end of depreciation: 10%; depreciation period: 10 year, except for MACRS: 5 and 15 year (half-year convention))

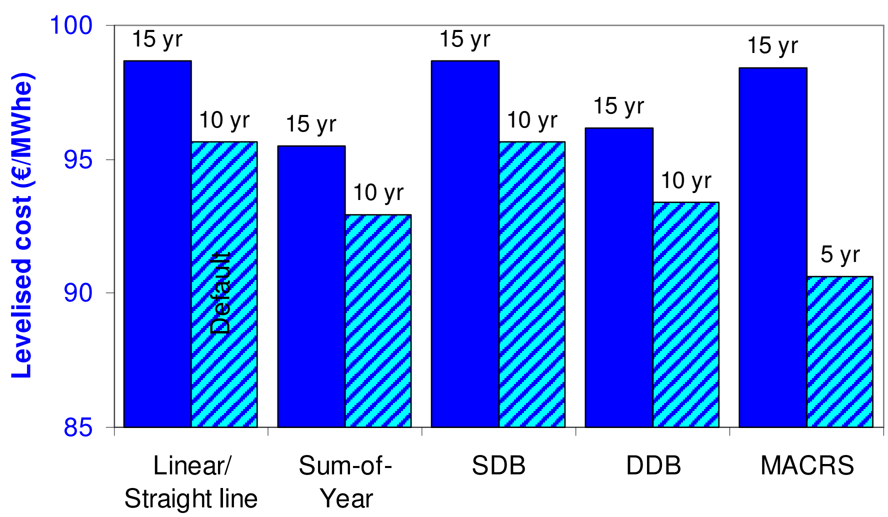

Figure 2-10 Levelised cost of electricity for the 20 MW onshore wind energy reference project: as a function of fiscal depreciation methods and terms (no residual value)

(SDB resp. DDB: single resp. double declining balance depreciation, with switch to straight line depreciation; MACRS: Modified Accelerated Cost Recovery System)

The faster the asset can be depreciated, the higher the net present value of the tax reductions will be and the lower the levelised cost of the project (provided that the project itself will generate income, or that loss carry-forward can be applied). This is shown in Figure 2-10 for the 20 MW wind onshore reference case. It clearly shows that the 5 year MACRS depreciation (which is applicable to RES in the USA) results in the lowest levelised cost, due to both the shape and the short term of the depreciation. As compared to the default reference case, costs vary from -5% to +3%. The 'sum-of-year' and 'double declining balance with shift to straight line' methods result in the largest cost reductions.

The availability of tax loss carry-back or -forward is used to harvest the tax benefit of spreading negative EBT (earnings before tax) over years with positive EBT, thus reducing taxable income. In the comparative assessment for this study only tax loss carry-forward is considered, which is allowed in the countries considered. As we assume project financing cases without any provisions to deduct negative EBT from other taxable income, tax loss carry-forward arrangements generally result in lower levelised cost of electricity.

The policy implications can be summarised as follows:

- General or RES-specific fiscal policies that allow for flexibility in fiscal depreciation, can reduce the levelised cost of renewable energy.
- Short fiscal depreciation terms and/or schemes with large initial depreciation of assets have the highest cost reductions.
- Flexibility in terms of tax loss carry-back or -forward should be offered to RES projects.

Combined effect of adjusting financial parameters

Policies and measures that favourably affect the key financial parameters, can reduce overall levelised energy cost significantly. In our example, by changing equity, debt, and fiscal parameters favourably (RoE from 15% to 10%, 10 year linear depreciation into 10 year sum-of-year fiscal depreciation, DSCR from 1.35 to 1.3, debt rate from 6% to 5%, debt term from 10 to 15 year), levelised cost could be reduced by 23% as compared to the reference case presented in Table 2-1, from 96 to 74 €/MWhe (see Figure 2-11).

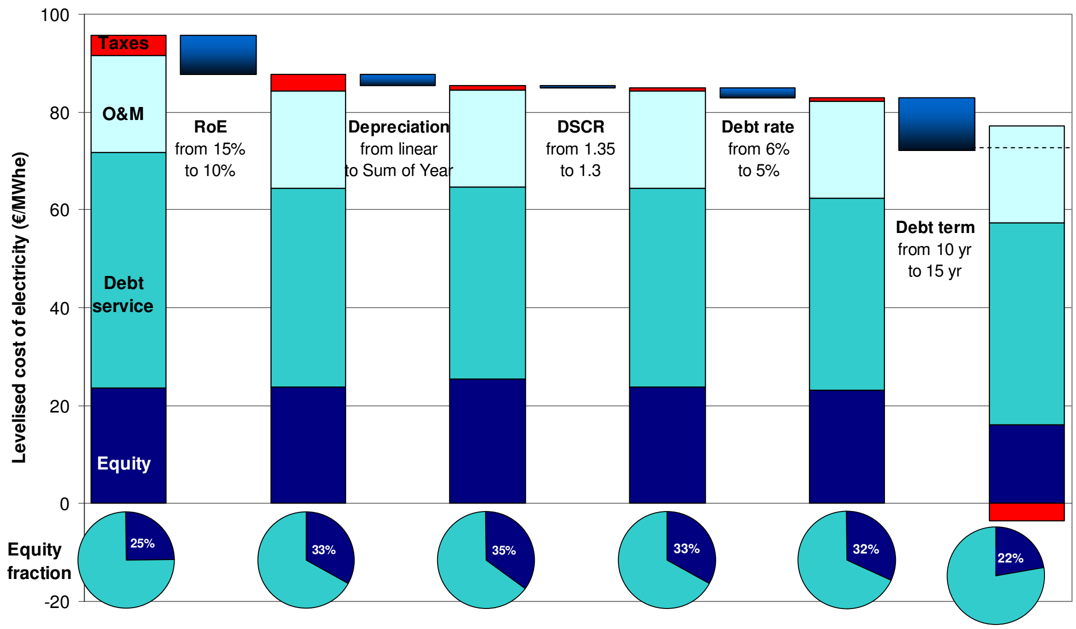

Figure 2-11 Levelised cost of electricity and equity fraction for the 20 MW onshore wind energy reference project: as a function of cumulative improvement in key financial parameters: required return on equity (RoE), fiscal depreciation scheme, debt service coverage ratio (DSCR), debt rate, and debt term.

Figure 2-11 illustrates that the effect of changing the required return on equity and the debt term has the largest impact on the levelised cost of electricity in this example. Both parameters can directly be influenced by policies and measures, and the design of associated support schemes. The figure shows that a stable and reliable policy and market context (resulting in longer debt terms and a lower required return on equity) potentially has significant impact on the cost of capital. Note that the cost data in the figure are still without assuming any production support from feed-in, feed-in premium, or certificates. However, their design does highly affect the risk assessment by the financial sector, and hence the cost of capital.

The policy implications can be summarised as follows:

- A favourable generic and RES-specific investment climate can result in levelised cost savings of over 20%. These savings can be attributed to reductions in the cost of capital.
- Policies and measures and associated support schemes that anticipate on the risk perception by investors and lenders, have lowest costs of capital. In designing support schemes, the expertise of the financial sector should be involved.

In real project finance, more design parameters play a potentially important role than the ones presented above. The selection presented here concerns a rather conventional, generic approach, typical for a sensitivity analysis that would be made in the early project development phase. Especially for large-scale projects, “financial engineering” will provide tailor-made solutions, which make optimal use of fiscal and financial instruments.

In the next chapter we will discuss how renewable energy policy schemes affect the key financial parameters that determine the cost of capital. We will also address how these policies could be improved based on a more detailed assessment of some reference cases for a selected set of national policy schemes (chapters 4 and 5).

3 Overview of policies and measures in selected IEA countries

This chapter gives an overview of policies and measures which are (suitable to be) applied in selected IEA countries for stimulating increased deployment of renewable energies. Major design features of these instruments – especially those potentially affecting financing risk – are briefly described.

3.1 Policy types and general design aspects

A range of different policy instruments is available to support increased deployment of RES. The next sections cover the main financial support instruments that are being applied in different forms, such as:

- feed-in and premium tariffs,
- quota obligations,
- tendering schemes, and
- fiscal and other support incentives such as direct production support, investment subsidies, low interest loans and different kinds of tax measures.

Besides financial support, RES projects heavily depend on permitting and grid connection procedures, thus section 3.6 covers policies to reduce administrative and grid barriers, which will notably affect the costs of renewable energy by affecting the market value of projects that are being offered for financial closure. Climate change mitigation policies, which do affect the competitiveness and the long-term prospects of RES and thus the investor confidence are touched upon in the last section.

Figure 3-1 shows the dominant financial support systems that can be found in selected IEA countries for electricity generated from renewable energy sources (RES-E) (see Annex 1 for a presentation of the respective country fact sheets[1]). Note that this classification is not rigid: Some countries have different support systems for different technologies, whereas Spain for example allows producers to choose between two systems. In Minnesota and Ontario projects receive support from two support systems in parallel. Note also that even within each category of

[1] The following countries/regions were assessed in more detail: Canada (Ontario and Québec), Denmark (DK), France (FR), Germany (DE), Ireland (IE), Italy (IT), Japan (JP), The Netherlands (NL), Norway (NO), Portugal (PT), Spain (ES), United Kingdom (UK), and the United States of America (California and Minnesota)

support instrument, the specific design can vary strongly from one country to another.

Figure 3-1 does not show incentives like low interest loans and tax measures. However, their importance should not be underestimated as in most countries these incentives are applied additionally to the dominant support instrument. Experience shows that one single type of support instrument is often not the most effective way to develop the full spectrum of renewable energy sources available in a country[2]. Most renewable energy projects have been realised through a combination of support measures instead of one single support instrument. For example in Germany feed-in tariffs for PV were combined with soft loans under the "100,000 roofs" programme, which led to a strong increase in implemented PV capacity.

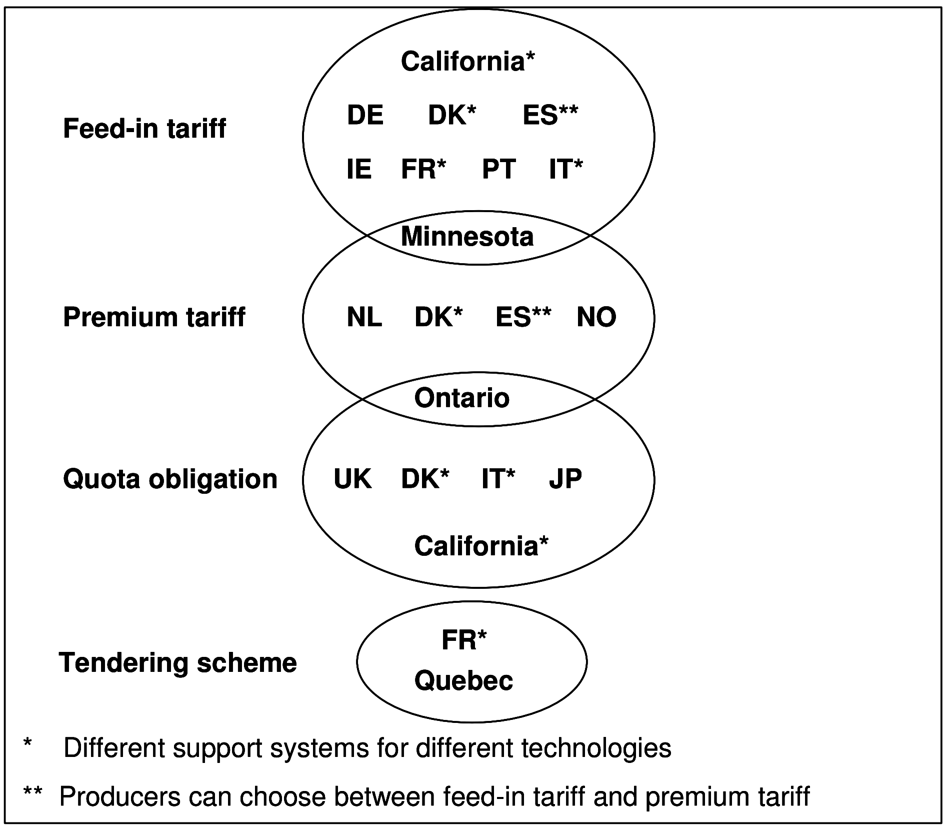

Figure 3-1 Dominating financial support instrument in selected IEA countries

For large-scale applications of heat generating renewable energy sources (RES-H) only few financial support schemes have been implemented. Sometimes, heat

[2] OPTRES (2007)

generation in co-generation units is supported via a bonus to the feed-in tariff or premium tariff of electricity. Also, tax measures are in place to reduce project costs.

The world of RES support schemes has been very dynamic over the last decade, with governments seeking to improve the effectiveness and efficiency of the support schemes in place. RES-E support schemes are being optimised based on best practice and lessons learned from own experiences and experiences in other countries.

Policy design and risks
As can be seen from Figure 3-2, the generic design of the support scheme has impact on the risk profile. The figure shows three prototypes of support schemes for renewable energy sources generating electricity (RES-E) that can be found in several IEA countries.

On the left hand side the *quota obligation system* is depicted where the government sets multi-annual targets for the share of renewable electricity in total electricity production or consumption. For each unit of electricity produced, certificates are generated that can be traded on a certificate market ('green') to parties needing these certificates in order to comply to the obligation. At the same time the generated electricity is being sold at the conventional electricity markets ('grey'). The value of both certificates and electricity are determined by the respective markets, and the risk profile of a project under such a scheme is determined by various policy and market design parameters, as well as the use of risk mitigation measures (e.g. long-term contracts for certificates and/or electricity).

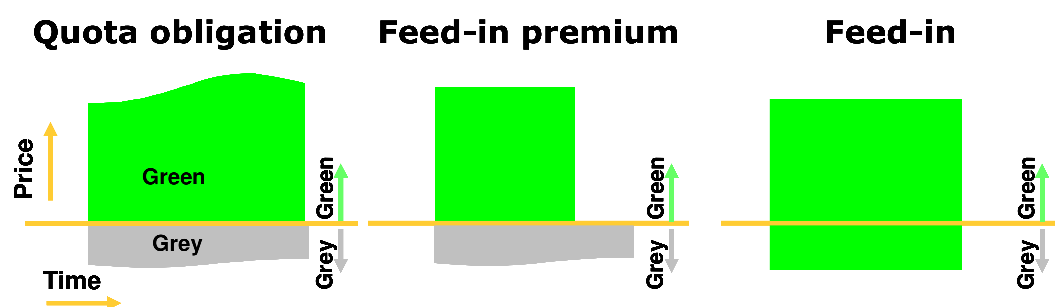

Figure 3-2 Prototype design of three policy support schemes for renewable electricity generation (RES-E): quota obligation scheme (*left*), feed-in premium scheme (*middle*), and feed-in tariff scheme (*right*). Renewable electricity can have a market value on certificate markets ('green') and/or on conventional electricity markets ('grey'). The schemes affect the variations in market prices and hence the risk profile of a RES-E project.

Feed-in premium schemes as depicted in the middle of Figure 3-2 eliminate part of the market risks of the quota obligation system, by offering a fixed price for the 'greenness' of the generated electricity during a fixed period of time. On the right hand side the *feed-in system* is depicted: for each unit of electricity a fixed feed-in tariff is being payed to the producer for a fixed period of time. This scheme largely eliminates the market risk for most RES.

General design aspects

Some general aspects described below apply regardless of the chosen policy instruments.[3]

Long-term and ambitious targets

Long-term and sufficiently ambitious targets should be set in order to ensure a sufficient level of investor security. As soon as deployment levels are approaching targets, a revision of the targets should be triggered.

Stable support policy

The policy instrument should remain active long enough to provide stable planning horizons. It follows that stop-and go policies are not suitable and that, for a given project, the support scheme should not change during its lifetime. Policy changes should only apply to new projects and should be announced well-ahead in order to give projects under development planning reliability, ideally reflecting typical project development duration of one to four years.

Source of funding

Funding for support can either be sourced from the state budget or from a surcharge on energy tariffs. The latter has the advantage that support schemes are affected less by budget constraints.

For example, the funds for the premium tariffs in the Netherlands are on the government budget, whereas in Germany the feed-in tariffs are paid for by the electricity consumers. Given the significant rise in government expenses for RES-E, the history of Dutch support for RES-E has shown several changes in budgets and assigned tariffs, whereas the even larger rise in RES-E support in Germany hardly had any impact on tariffs or total levels of support.

Duration of support

Duration of the support for single projects should not be unlimited but be restricted to a certain time frame in order to avoid over-funding. The duration should ideally reflect the technology's economic lifetime in order to allow for longer debt terms and/or refinancing, which reduces financing cost.

[3] Compare also Ragwitz et al. (2007)

3.2 Feed-in tariffs and premium tariffs

Feed-in tariffs guarantee a fixed financial payment per unit of electricity produced from renewable energy sources. This support can be for both the physical electricity and the green value together (fixed feed-in tariff) or it can just be a premium for the green value, while the producer receives the rest of his income from selling the electricity on the regular electricity market (premium tariff). A combination of both fixed feed-in tariffs and premium tariffs is also possible and currently operational in Spain, where RES-E producers can choose every year which support system they want to use.

Duration of tariffs
Tariff levels are usually guaranteed for a longer period, e.g. 10 up to 20 years. In this way they provide long-term certainty about receiving financial support, which is considered to lower investment risks considerably.

Technology-specific tariffs
Technology-specific tariffs can be used in order to support different technologies while avoiding windfall profits for cheaper technologies.

Stepped tariffs
Tariffs can be stepped according to site conditions (for example average wind speed) in order to avoid windfall profits for projects at the more favorable sites.

Tariff degression
A fixed or regularly determined degression of tariffs over time for new installations can be used in order to reflect for economies of scale and learning. Tariff levels should be evaluated in regular intervals and be adjusted if necessary, but changes should only apply to new installations.

Front loading the payment stream
Instead of having a constant tariff level for the complete support duration, it can be considered to increase tariffs for the first years of a project while decreasing tariffs in the last years[4]. Without increasing the total sum of financial support, this can help to reduce financing cost. This is for example applied in the German support for wind energy, where for most projects feed-in tariffs are reduced in later years.

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[4] Compare Wiser and Pickle (1997)

3.3 Quota obligations

Quota obligations, also called renewable obligations or renewable portfolio standards (RPS) impose a minimum share of renewables in the overall electricity mix. This obligation can be imposed on consumers, retailers or producers. A quota obligation system is often combined with tradable green certificates (as in the UK), although this does not necessarily have to be the case (as in California). Financial support for the RES-E producer comes from the fact that an obligated party failing to meet its quota obligation faces a penalty. The financial value of RES-E or the green certificates is determined by the level of the quota obligation, the size and allocation of the penalty, and the duration of RES-E being eligible under the quota system. Appropriate fine tuning of a quota obligation system is of utmost importance for effective promotion of RES-E. If the quota obligation is set too low, or if the penalty is too low or not enforced, then the value of RES-E in the market will be low, generating insufficient stimulation to initiate new RES-E projects.

Time horizon of the quota obligation
Obligation levels need to be set well in advance and the quota obligation should be guaranteed to be in place for a sufficiently long time period in the future in order to guarantee future demand for RES-E. For instance, in the UK the obligation level has been set until 2016 while the obligation itself is guaranteed to remain in place at least until 2027.

Penalty
Penalties should be set well in advance, significantly above green certificate prices, and enforcement should be guaranteed. For example in Sweden the penalty is set at 150% of the certificate price. Recycling of penalties to RES-E projects as applied in UK can add a ‘positive’ incentive for RES-E projects to the ‘negative’ incentive for obliged parties. However, in an oligopolistic market the penalty can loose its effectiveness if obliged parties manage to negotiate contracts for certificate purchase that foresee the recycling to be paid to them, and thus a loop is created where a large share of the penalty paid by the obliged party is recycled to its own pocket.

Market liquidity
In order to have markets functioning well, market design, size and competition are key parameters. Via the obligation a demand is being created, but with barriers still existing on the supply side (e.g. grid access, siting problems) no real supply can be generated. This in turn could result in high prices being paid for only few realised projects.

Minimum tariff
Minimum tariffs can be introduced in order to increase investment security in case of fluctuating prices. For instance in Belgium the obligation to purchase at a minimum price is on the Transmission and Distribution System Operator. Peculiar to the Belgian system are the technology-specific minimum tariffs, a feature which is usually only known from feed-in tariffs.

Technology-specific support
There are several options to support currently less economic technologies while avoiding windfall profits for cheaper technologies: Separate quotas (bands) per technology, technology-specific certification periods (duration), or differentiated values (more or less than one certificate per MWh). But also a combination with a feed-in premium can be envisaged.

Long-term contracts
Long-term contracts (e.g. 10 years) for both the physical electricity and the green certificates can reduce price risks for both RES-E producers and obliged parties. Obliged parties might not always be interested in signing long-term contracts, especially if certificate prices are expected to decrease.[5] Therefore the government can oblige obligated parties to offer long-term contracts as it is done for example in the Californian system.

3.4 Tendering schemes

A call for tender for renewable energy projects can be issued by a national government or other institutions, asking project developers to submit bids to develop renewable energy projects. Tenders usually specify the capacity and/or production to be achieved and can be technology- or even project/site-specific. Winning parties are usually offered standard long-term purchase contracts while the price is determined competitively within the tender procedure. Purchase can also be limited to green certificates in case of RES-E. Thus the support itself can be compared to feed-in tariffs/premium tariffs, while the support level is determined by the market. Quota systems with mandatory long-term contracts also have comparable features, despite for the counterparty risk in case of quota systems. Tendering allows for incorporation of additional conditions, e.g. regarding local manufacturing of technology.[6]

A disadvantage of the system however is the risk that the actual cost of realisation of the project turns out to be higher than that predicted when drafting the bid, or that the project will not be bankable after all. This might lead to the granted project

[5] Agnolucci (in press)
[6] Lewis and Wiser (2006)

not being realised. In several countries that had a tender scheme in place, such as Ireland and the UK, the overall number of projects actually implemented has been very low, resulting in a much lower penetration of renewable energy projects from tender schemes than originally anticipated. These countries abolished their tender schemes. In California, the tendering scheme that is used under the renewable portfolio standard (RPS) scheme encounters similar difficulties, either related to projects not being bankable or to grid issues. In France and Canada (Ontario and Québec, see section 4.4.6) tendering schemes are in place for large-scale RES-E projects, whereas Denmark has had tenders for offshore wind energy only.

Another disadvantage is that a successful tender procedure might result in many project initiatives being prepared in vain. The second call for tender in Québec for 2000 MW onshore wind energy was overbooked by almost a factor of 4.

Penalties
A penalty for non-compliance can be implemented in order to avoid unreasonably low bids. Penalties can also be applied to projects exceeding deadlines.

Share part of the price risk
By incorporating corrections for inflation, currency exchange rates and market prices of key commodities (e.g. steel, biomass) between tender closure and realisation of the project, a significant part of the financial risk can be transferred from the project developer to the tendering body (see the example of Québec, section 4.4.6).

Continuity of calls
Long-term continuity and predictability of calls should be ensured in order to avoid stop-and-go development of the renewable industry.

Streamlining of interacting policies
Other policies affecting the realisation of winning projects, like for example spatial planning, should be streamlined in order to ensure the tendered capacities can actually be realised.

3.5 Fiscal and other support incentives

Fiscal and other support incentives aim to promote renewable energy by investment subsidies, low-interest loans, and different tax measures like for instance tax deductions or flexible depreciation schemes. Fiscal incentives play an important role in the promotion of RES, although unlike for biofuels - where tax exemptions have recently stimulated substantial development in some countries - fiscal incentives are secondary instruments to support other RES-E instruments rather than being the main support instrument in the majority of countries. An exemption is Finland, where tax measures combined with investment subsidies are the main support instrument for the development of RES-E.

The largest shortcoming of fiscal incentives is their instability: They usually rely on government budgets and are thus subject to frequent political negotiations and annual budget constraints. Frequent policy changes increase risk in the project development phase and hinder the development of the renewable energy industry. Alternatively, fiscal incentives could be announced and guaranteed for a couple of years in advance. They could theoretically be financed through a surcharge on energy consumption, which adapts automatically to the amount of support paid, like it is done in some feed-in schemes. These measures are likely to increase stability and reduce regulatory risk.

Direct production incentives

In certain schemes a certain production incentive is given for each unit of renewable electricity produced over a given period of time (e.g. 10 CAN$/MWh over 10 year, in the EcoENERGY for Renewable Power in Canada). This production incentive is not intended to fully bridge the gap between electricity market prices and the price of renewable electricity, but it contributes to removing part of the market risks of a project. The direct production incentive is considered as gross revenue and hence taxable. This incentive typically requires other complementary measures to make the project viable and bankable. In Canada, these additional measures are designed at the provincial level (tendering schemes, renewable portfolio standard (RPS).

Investment subsidies

Investment subsidies - also called capital grants - are paid up-front on the basis of installed capacity and thus help to reduce risk and capital cost. They have successfully been applied for instance in developing the Japanese PV sector. Support levels can be determined like in the case of feed-in and premium tariffs, depending on technology and/or site and the economics of an average project. The support level can also be determined based on cash flow analysis for individual projects like in the Norwegian system. The latter implicitly considers technology- and site-specific conditions which helps to give sufficient support while avoiding windfall profits but it limits the economic incentive for increasing efficiency.

Low interest loans and loan guarantees

Interest rates and repayment periods of loans have a major impact on the overall cost of RES projects. Especially new technologies, smaller projects or project developers without a proven track record often experience difficulties in obtaining commercial loans at reasonable conditions. Governments can increase commercial viability of projects significantly by offering low interest loans or loan guarantees.

Governments can offer low interest loans for specific technologies directly through state-owned banks or through subsidies to commercial banks. These loans can be characterised by lower interest rates and/or longer repayment periods. Low interest loans have been applied successfully in for example Spain and Germany.

Governments can also offer just loan guarantees for certain projects. In that case the government guarantees debt repayment to the lending bank, thus reducing risk and hence interest rate (e.g. 1 to 2%), debt term and debt service conditions of the loan[7].

Flexible/accelerated depreciation schemes

Flexible/accelerated depreciation schemes allow writing off a project faster (or differently) than usually would be allowed. Doing so, the tax benefit of depreciation can be maximised by the equity provider, provided that this equity provider has a net income that is large enough to absorb this tax deduction. In general, an accelerated depreciation scheme will result in a higher overall net present value of the project. The 5 year MACRS depreciation for RES in the US is an example of an accelerated depreciation with significant cost reductions as a consequence (see Figure 2-9 and Figure 2-10).

Investment or production tax exemptions

Investment or production tax exemptions (also called tax relief or tax credits) reduce the tax burden of a project. The former support is linked to installed production capacity while the latter is in relation to the amount of energy production. The effect of the former is similar to that of an investment subsidy (which benefits the project), whereas the latter only increases the profit for the equity provider. In project finance, the former has a favourable impact on the debt/equity structure under the same debt service requirements, the latter not.
The Production Tax Credit in the US for example has stimulated considerable deployment of especially wind energy. However, success has been impaired by the stop-and-go nature of the policy.

> **Consistency with minimum tax requirements**
> Minimum tax requirements, like the Alternative Minimum Tax in the US, can set minimum tax rates for individuals or companies, and thus limit the extent to which tax exemptions, accelerated depreciation schemes and the like can be applied (cumulated) by taxpayers. This also limits the potential incentive from these kinds of policies under a minimum tax regime.

[7] Harris and Navarro (1999)

Consistency with preferred debt-equity ratio

Some tax measures only concern the equity (provider) within a project. At the same time the majority of project developers strives to minimise the equity within a project (while maximizing the debt) in order to maximise return on equity. Thus, projects with a very low equity share might not be able to take advantage of all tax measures to the full extent. The US Production Tax Credit for example can only be fully utilised with an unusually high equity share, which on the other hand would negatively influence the return on equity.[8] Only entities with other higher income can benefit from this scheme.

Support of capacity versus production

If the amount of investment subsidies, investment tax exemptions or accelerated depreciation a project can receive is linked to installed capacity, project developers can be stimulated to focus on capacity rather than production. For example, as part of industry support for the Dutch wind industry in the 1980s, the Dutch investment subsidy scheme for wind energy lead in the past to wind turbines which were optimised with regard to capacity, not to energy production. On other markets with production support these turbine-designs were not competitive[9]. This example shows that support should not exclusively be linked to installed capacity. However, combining a capacity-based support with any form of production incentive can overcome this problem. Capacity-based support might be especially helpful in case of prototype/demonstration projects, where the risk of lower than envisaged production would be prohibitive for the project in case of production-based support.

Non-taxpaying companies benefiting from tax measures

A possibility to allow also not (yet) taxpaying companies to profit from tax measures is applied in the Canadian Renewable and Conservation Expenses scheme (CRCE). "A flow-through share is available to certain types of renewable energy companies to facilitate financing their exploration and project development activities. Eligible companies issue these equity shares to new investors. Investors receive an equity interest in the company and income tax deductions associated with new expenditures incurred by the company on exploration and development."[10]

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[8] Wiser and Kahn (1996)
[9] Kamp (2002)
[10] www.cra-erc.gc.ca

3.6 Policies to reduce administrative and grid barriers

Apart from the economic barriers related to the design of the support schemes, further deployment of renewable energy sources also faces a number of non-economic barriers. Administrative barriers are most severe in the authorisation procedures for new renewable energy projects. Grid barriers can be an important obstacle especially in the case of large-scale RES projects and variable sources like wind. These non-economic barriers need to be addressed in order to enable support schemes to be effective. Potential policies for reducing barriers are explained below.

One-stop authorisation
Often numerous authorities (national, regional and municipal) are involved in the permitting process. Lack of coordination between authorities often leads to delays, investment uncertainty and a multiplication of necessary efforts. One reponsible authorisation agency appointed by the government, such as for example the Bundesamt für Seeschifffahrt und Hydrographie for offshore wind in Germany, can drastically reduce the administrative burden for the developer related to authorisation of new projects.

Response periods & approval rates
Currently, time needed to obtain all necessary permits for the construction of a RES plant can take many years. For onshore wind projects authorisation procedures may take several years, which negatively affects the development of the market. sometimes it can also be unclear to the developer what the exact length of a procedure will be. This increases risk and cost of a RES project. To overcome these obstacles, clear guidelines for authorisation procedures can be implemented: Obligatory response periods for the authorities involved can be incorporated in such procedures. Setting approval rates can be a tool for checking the streamlining of authorisation procedures.

Pre-planning
Obtaining a permit related to spatial planning is often the step which takes most time in the authorisation procedure, especially for biomass and wind energy projects. This is due to the fact that future developments of RES projects are usually not taken into account when national and regional authorities draw up their spatial plans. As adjustment of existing spatial plans to new RES initiatives can take a very long time, and can heavily frustrate the realisation of the initiative, authorities could be stimulated to anticipate the development of future RES projects in their region by

allocating suitable areas. Pre-planned areas currently exist in Denmark and Germany, where municipalities are required to assign locations available to project developers for a targeted level of RES capacity. In these areas, permit requirements are reduced and authorisation procedures are shorter. Also in Sweden areas of national interest for wind exist, while in France the assignment of areas for wind energy is currently under preparation.

Increase grid capacity
Many parts of the existing electricity grid have little capacity available for the connection of large-scale RES power plants. In addition, the existing grid was designed focusing on the transmission of electricity generated by large conventional power plants. The profile of electricity generation from intermittent sources like wind sometimes poses challenges to the current design of the grid. The geographical spread between availability of RES-E sources on the one hand and electricity demand on the other hand can result in grid barriers. For example in the UK there is limited grid capacity between wind abundant Scotland and electricity consuming Southern England, which calls for important enforcement of the north-south grid connection. In some areas in for example Italy and Portugal, grid expansion and reinforcement is urgently needed in order to prevent frustration of future RES developments. For the future development of grid-connected RES-E, it is of utmost importance that when grid expansion and reinforcement plans are being developed, future realisations of renewable energy projects are taken into account, like it was done in the German multi-stakeholder grid studies.[11]

Transparent grid connection procedures
Procedures related to grid connection and accounting rules for the grid costs are not always transparent to the developer. This is often caused by the fact that countries have not yet formulated transparent and non-discriminatory rules for bearing and sharing of necessary grid investment costs. In many cases in the past, including for example wind park developments in France and Spain, the attribution of costs for grid connection has been controversial. The European Commission recommended obliging grid operators to cover costs associated with grid infrastructure development necessary for new RES projects.[12]

[11] DENA (2005)
[12] European Commission COM (2005) 627

3.7 Climate change mitigation policies

RES support policies as mentioned above are currently necessary for most RES in order to be competitive with conventional production technologies based on fossil fuels, nuclear energy or large hydro. Thus the level of support needed does not only depend on the RES technology, but also on the reference cost for conventional production. These reference cost depend on the one hand on the existing subsidy and tax regime which applies for conventional production and on the other hand increasingly on the climate change mitigation policies in place in a country.
Climate change mitigation policies include:

- Emission reduction targets (both domestic and internationally binding)
- Emission taxes and emission trading, both leading to a price for greenhouse gas emissions
- Energy taxes

Increasing reference cost due to higher prices for fuel or technologies, reduction of subsidies or increasing impact of climate change mitigation policies, reduces the level of support needed for RES. Ambitious and stable climate change mitigation policies improve long-term prospects for RES and will thus help increasing investor confidence.

4 Analysis of selected policies and measures with respect to cost of finance

This chapter presents a more detailed analysis of the impact of selected policies and measures on the financing risks and costs for different large-scale RES projects.

4.1 Introduction

In this chapter a more detailed analysis of selected policies and measures will be made, for a selection of reference technologies. This exercise could be seen as a pre-feasibility assessment for a fictitious corporation that wants to invest in large-scale renewable energy projects in several countries and under different policy support schemes (assuming that the technologies have the same technological performance in each country). What would be the required revenues to make the project viable from both the investor's and lender's perspective?

For each of these combinations of reference technologies and policy frameworks the impact of policies and policy instruments will be assessed:

- quantitatively: what impact have policy instruments on the costs of RES (based on a simple cash flow model[1])?
- semi-quantitatively: how are perceived risks translated in financial parameters (e.g. interest rate, internal rate of return (IRR), weighted average cost of capital (WACC)), how do they differ from conventional energy technologies and how do they affect financing costs)?
- qualitatively: what is the level of complexity of the support measure? is the support measure (seen as) reliable and stable? what are other effects of the measure (e.g. development of national industry)?

Comparison of results for the reference projects across the selected national policy frameworks will provide key lessons on the impact of policy design on RES financing. What barriers are encountered by this corporation that result in higher financial costs? What best practice examples illustrate the successful

[1] The cash flow model determines the levelised cost of electricity or heat from the RES. Key inputs are project investments, revenues, capital structure (debt/equity ratio), debt interest rates, debt term and taxes, all depreciated over the technical lifetime of the RES. The model results show the sensitivity of RES costs to changes in financial parameters (see Annex 2).

implementation of policy designs on either international, national and regional level, that reduce perceived risks of RES? Existing policy measures aimed at reducing costs of capital will be addressed.

The semi-quantitative analysis is partially based on interviews with key stakeholder representatives, as information is often not published or confidential. Based on this analysis, alternative policy designs will be discussed as well as other measures that reduce the risk to investors.

Table 4-1 Selection of technologies

Technology	Typical size	Remarks
Wind onshore	> 20 MWe	
Wind offshore	> 100 MWe	
Biomass – CHP	> 10 MWe	Forestry residues co-generation (combustion) (efficiencies: 25% electrical and 65% heat)
Solar photovoltaic	> 0.5 MWe	

Table 4-2 Selection of combinations of countries/regions and technologies

Country	Main type of support	Renewable energy technology			
		Wind onshore	Wind offshore	Solar PV	Biomass CHP
Germany	Feed-in tariff	X	X	X	X
France	Feed-in tariff + Tax measures	X	X	X	X
Netherlands	Feed-in premium + Tax measures	X	X		X
United Kingdom	Quota obligation	X	X		X
USA/California	Production Tax Credit (federal) + Quota obligation (RPS) (+ Feed-in premium)	X		X	X
Canada/Québec	Direct production incentive (federal) / Contract price based on tendering scheme for wind energy	X			

4.2 Renewable energy technologies and policy support schemes for detailed analysis

To better understand the way support schemes affect the costs of financing, six countries/regions will be assessed in more detail, for four large-scale RES projects. In consultation with the steering committee for this study the technologies presented in Table 4-1 will be assessed in more detail for the countries/regions that are presented in Table 4-2. **The assessment will concern the situation in 2006**.

With this selection it is believed that the different types of policy schemes are well represented for a group of technologies with different specific investment characteristics. In other words, it is believed that a more detailed financial assessment will provide us with new insight in the effects of different policy schemes on the costs of capital for different technologies.

<u>Technologies</u>

Wind onshore (> 20 MWe)
Onshore wind energy conversion is a well demonstrated and commercially available technology. For most locations, the project risks are well understood or known. An onshore wind project of 20 MWe equals 5 to 20 windturbines and total investments in the range of 22 to 36 M€.

Wind offshore (> 100 MWe)
Offshore wind energy conversion has considerable more risks as compared to onshore wind energy: the specific conditions at sea ask either for considerable modifications to windturbine concepts that are normally used in onshore situations, or for development of dedicated offshore windturbines. Furthermore, production yields have often more uncertainties, both under normal operating conditions and in case of failures (immediate repair will generally not be an option at sea). Due to the significant costs of grid connection, wind projects will be typically larger than 100 MW. This equals 20 to 50 windturbines and total investments in the range of 200 to 240 M€ (depending on water depth and distance to shore).

Solar photovoltaic (> 0.5 MWe)
Solar photovoltaic energy is a commercial technology with well known risks. A 500 kWe project would have investment costs in the range of 2 to about 4 M€. In this study we consider open space installations only.

Solid biomass combustion – CHP (> 10 MWe)
Electricity production and - even more - co-generation of heat and power (CHP) by combustion of biomass is not a standardised renewable energy technology. System

parameters are highly influenced by availability and type of biomass (which determines fuel costs or even fuel savings), and in case of CHP also heat demand, heat prices, and heat demand patterns, et cetera. Biomass to energy conversion has higher operational expenses (OPEX) as compared to RES without fuel consumption. In the detailed assessment a default biomass-CHP will be defined (with electrical and heat efficiencies of 25% and 65% respectively), fired with forestry residues and with default assumptions on the project context, fuel costs, the value and pattern of the delivered heat, et cetera, for all countries. The combustion technology is commercially available and project risks are often well understood or known. Investment costs for a 10 MWe plant are typically in the range of 30 to 50 M€.

Note that for this reference case we will have to make (over)simplifications on several design parameters that most likely will not do justice to the real investment climate in individual countries. The specific implications of CHP (as compared to the electricity-only case) on the costs of capital will be addressed in the overview section.

Policy schemes

In Annex 1 an overview table is presented of the main support schemes for large-scale applications of renewable electricity and heat in selected countries. These countries cover the main support schemes for renewable energy technologies. In several support schemes combinations of support mechanisms can be found.

With the selected countries (see Table 4-2) a good representation of these schemes is achieved. The selection covers both feed-in tariff, feed-in premium and quota obligation support schemes, as well as additional tax support instruments and a tendering scheme. Only those policy schemes are incorporated that were in place during 2006 (either at country or regional level) and that result in a significant reduction in the gap between the costs of (new) renewable energy technologies (‘green’) and market prices (‘grey’). As an indicative benchmark, production costs for onshore and offshore wind energy and combustion of forestry residues in a co-generation plant are usually within the range of 60 to 140 €/MWhe. For large-scale projects of solar photovoltaic energy this range is typically above 200 €/MWhe in the countries with significant resource potentials. The support schemes for the selected combinations result in a significant reduction of he levelised cost of electricity.

The selection also covers relative emerging markets and (more) established markets, both in terms of countries and technologies (e.g. offshore versus onshore wind energy).

For onshore wind energy a comparison of all countries is possible. Biomass co-generation will be assessed for all countries except Canada/Québec. Due to lack of resources and/or specific (significant) policy support for offshore wind energy and solar photovoltaic energy, these options will only be assessed for three or four countries/regions.

4.3 Technology characterisations

In Table 4-3 the technology characterisations that will be used in this analysis are presented. In order to account for the different resource characteristics of different regions, both a default (D) and variant (V) value for the full load hours (or capacity factor) are presented.

The data in this table are based on several studies[2]. The reported range in costs is significant (after correction for exchange and inflation rates), even for technologies that can be regarded to compete on a global market such as solar photovoltaic modules and wind turbines. Local market conditions can largely affect balance of system costs such as system integration and grid connection. For the purpose of this study, we consider the default and variant data in the table to be fairly representative for the countries assessed.

[2] Van Sambeek, et al. (2004), Van Tilburg et al. (2006), Eurelectric (2007), UK-DTI (2007), Ernst & Young (2007), IEA Wind Energy (2006), IEA PVPS (2007), IEA Bioenergy (2007), NREL (2006a,b), Ragwitz et al. (2003)

Table 4-3 Assumptions on technology characterisations (2006)

			Wind onshore[a]	Wind offshore[b]	Solar[c] photovoltaic	Biomass CHP
Technical parameters						
Capacity		MW_e	20	100	0.5	10
		MW_{th}	-	-	-	26
Full load hours	default D	h	2000	3000	950	4000
	variant V	h	2300	3500	1400	7500
Electricity production	D	GWh_e/yr	40	300	0.475	40
	V	GWh_e/yr	46	350	0.700	75
Heat production	D	GWh_{th}/yr	-	-	-	104
	V	GWh_{th}/yr				195
Fuel input	D	TJ/yr	-	-	-	576
	V	TJ/yr				1080
Technical lifetime		yr	15-20	15-20	20-25	15-25
Economical lifetime (def.)[d]		yr	15	15	15	10
Cost parameters (specific)						
Investment		€/kW	1200 [1100-1800]	2200[e] [2000-2400]	3500 [3400-7500]	3250 [3000-5000]
Operation&Maintenance	D	€/kW/yr	40 [40-70]	80 [65-115]	25	250 [90-400]
	V	€/kW/yr	,,	,,	35	,,
Fuel cost		$€/GJ_{fuel}$	-	-	-	3 [1.5–4]
Heat cost / revenue		$€/GJ_{th}$	-	-	-	5.5
Cost parameters (total)						
Investment		M€	24	220	1.75	32.5
Operation&Maintenance	D	M€/yr	0.8	8	0.0125	2.5
	V	M€/yr	,,	,,	0.0175	,,
Fuel cost	D	M€/yr	-	-	-	1.7
	V	M€/yr	-	-	-	3.2
Heat cost / revenue	D	M€/yr	-	-	-	2.1
	V	M€/yr	-	-	-	3.9

[a] Some support schemes are differentiated for turbine type. As a reference we use the Vestas V80-2.0 MW with a 75 meter hub height. [b] Ibidem, with a 60 meter hub height, located at 15 sea miles from shore at a water depth of 25 meter. [c] In this study we consider open space installations only. [d] The presented economic lifetimes are default values used for all country cases. In actual projects this parameter will be affected by for instance the timeframe of the main support scheme in place. The economic lifetime can change due to implementation of support schemes. This will be indicated in the country summary tables in subsequent sections. [e] Current (2008) project cost of offshore wind projects is significantly higher, well above 3000 €/kW.

4.4 Country characterisations

In the next sub-sections the key characteristics of the support schemes for the selected country/technology combinations will be presented. This will form the input for the cost assessment in the next section.

4.4.1 Germany

The most important mechanism for financing renewable electricity projects in Germany is the feed-in tariff scheme. It is complemented by low-interest loans from the state-owned KfW bank. Based upon the investment certainty of the feed-in tariff scheme, investment brokers have created a wide portfolio of renewable energy investment funds that attract private equity for RE investments. After tax incentives for renewable energy investment funds were abandoned in 2005 (see below), general tax law applies.

In the following paragraphs, the different financing schemes will be presented in more detail.

The feed-in tariff scheme

Germany has continuously utilized a feed-in tariff scheme for more than 15 years. From 1991-2000, a first feed-in law (Stromeinspeisegesetz) provided one single fixed feed-in tariff for all RES-E technologies. It mainly supported the development of wind energy. Further fast market growth for all RES-E technologies was stimulated by the Renewable Energy Sources Act (Erneuerbare-Energien-Gesetz, EEG) that was enacted in 2000 and amended in 2004. It grants privileged grid access, priority feed-in and technology specific payment rates for a predefined set of renewable energy technologies.

Tariff structure

The feed-in tariffs are technology specific and usually apply for a period of 20 years (except for hydropower with a term of 30 years for small and 15 years for medium plants). This way a high level of investment certainty is provided that lowers the cost of investment capital for project developers. The philosophy behind the technology differentiation is to support each renewable technology on its own cost level instead of privileging least-cost technologies only.

The year a plant is put into operation is relevant for the level of the tariffs, a the tariffs for newly installed plants are decreased each year with a technology specific degression rate, assuming technological learning curves that will lead to cost reductions. At the same time, an incentive is given to build plants as soon as possible. Degression rates are higher for less mature technologies like PV and not applied for mature technologies like hydropower. The tariff reductions do not always reflect real market developments, however. For example, prices for wind turbines and solar modules increased in 2006, due to increased steel prices in the case of wind turbines and a silicon shortage in the case of PV.

Table 4-4 gives an overview of the tariffs and degression rates for the selected technologies in 2006.

Table 4-4 Feed in tariffs and degression rates for selected technologies in Germany (2006)

Germany - Technology	Feed-in tariff 2006 (€/MWh_e)	Degression rate
Wind onshore[a]		
- initial tariff (year 1 – T); T ≥ 5	83.60	2%/yr
- basic tariff (year T – 20)	52.80	
Wind offshore[b]		
- initial tariff (year 1 – T); T ≥ 12	91.00	2%/yr
- basic tariff (year T – 20)	61.90	Starting 2008
Biomass from forestry residues (> 5 and ≤ 20 MWe)	81.50	1.5%/yr
Biomass CHP from forestry residues (> 5 and ≤ 20 MWe)	101.50	1.5%/yr
Solar photovoltaics (PV) (> 100 kW)		
- rooftop installation	487.40	5.0%/yr
- façade integrated	492.40	5.0%/yr
- open space installations	406.00	6.5%/yr

[a] For a Vestas V80-2.0MW turbine, with a hub height of 75 meter, the 5 year reference yield is 23,606,567 kWh, equal to 2361 full load hours. For the default case (2000 FLH) and variant (2300 FLH), the value of T equals 19.5 year (234 months) and 16.7 year (200 months), respectively.
[b] With a location of 15 sea miles from shore at a water depth of 25 meter, the value of T equals 12.8 year (154 months).

Tariffs for wind onshore depend on the energy yield of a specific plant compared to a "reference yield" that is calculated with characteristic plant parameters like diameter, hub height, rated power for a "reference site" (inland, 5.5 m/s wind speed, 30 m height)[3]. To receive guaranteed payments under the EEG, the wind power plant must produce at least 60% of the reference yield. This clause ensures that wind power plants are only built on reasonably productive wind sites[4]. The increased initial tariff for wind onshore is paid for a minimum of 5 years (this is the case at good coastal wind sites where 150% of the reference yield is produced during the first 5 years). Depending on the energy yield of the plant, it can be paid for up to 20 years. For every 0.75% the production is below 150% of the reference

[3] An overview of the reference yields of different wind power plants is given under http://www.wind-fgw.de/eeg_referenzertrag.htm
[4] Before the EEG amendment in 2004 when this clause was introduced, wind power plants were sometimes built on unproductive sites merely for favourable tax depreciation. This decreased public acceptance of wind energy.

yield, the period is prolonged by 2 months. By this differentiation wind power plants at medium wind sites receive a higher average remuneration than plants at good wind sites.

For wind offshore, the initial tariff is paid for a minimum of 12 years if the plant is put into operation before 2011. If the plant is built more than 12 sea miles offshore and/or deeper than 20 meters, the period is prolonged by 0.5 months per extra sea mile distance and 1.7 months per extra meter sea depth.

For biomass, a wide range of tariffs apply that are differentiated by plant size, type of biomass (forestry or agricultural residues, general wood or industrial waste wood), utilization for CHP and application of innovative technologies (e.g. gasification or fuel cells). For larger plant sizes (> 5 and ≤ 20 MWe), only two tariffs apply (see Table 4-4). Plants > 20 MWe do not receive support under the EEG.

For solar PV, tariffs are differentiated by plant size and type of installation (rooftop, façade integrated or open space).

All feed-in tariffs will be reviewed in 2007 according to the regular schedule. First announcements of the Ministry of Environment indicate that tariffs for offshore wind will be increased and the degression rate for wind onshore will be decreased. Tariffs for PV will be decreased at a higher degression rate.

Priority grid access and feed-in

Network operators are obliged to grant renewable energy project developers access to the nearest grid connection point. The RES project developer only pays the grid costs up to this point ("shallow" grid connection charges). If grid reinforcements become necessary in the distribution or transmission grid, the grid operator is obliged to carry out these reinforcements. This regulation minimizes the risk of unforeseen grid costs for the project developer. On the other hand, it increases the burden on the network operator, and reinforcement costs will increase total costs for consumers. In practice, necessary reinforcements require long lead times and administrative procedures, especially in the case of transmission networks; therefore the reinforcement process does not match the speed of RES development.

The grid connection of offshore wind farms is a special infrastructural challenge, because it requires long and costly sea cables. Until autumn 2006, it was not clear who would pay for these costs; this uncertainty constituted a major risk factor to all project developers. To speed up the stagnating German offshore development, a law was passed in November 2006 (Gesetz zur Beschleunigung der Infrastrukturplanung) that assigned the responsibility and costs for the grid connection of offshore wind farms to the network operators until 2011. The new law greatly reduces the costs and risks of offshore wind development in Germany. It also reduces the total costs of the infrastructural investment: network operators will be granted better financing conditions than individual project developers.

Once RES-E plants are connected and operating, the network operator is obliged to accept and remunerate the renewable electricity with priority. The additional costs for the feed-in tariffs are passed via the electricity suppliers to all electricity consumers. The transmission system operator is responsible for forecasting and balancing the RES feed-in. The RES operator does not pay for imbalance settlement, and therefore does not carry any balancing risk. If wind energy operators were to be responsible for balancing, this would increase their costs significantly.

In principle, the feed-in of renewable electricity is guaranteed by law. However, the network operator can cut off RES plants if the network is already congested with electricity from other renewable energy plants. This means that plants that have been connected last will be cut off the network first. In regions with high RES feed-in and weak grid infrastructure (especially Northern Germany), such congestion management by now poses a considerable risk to the RES operator, since the times of cut-off mean a loss of income to the RES project. For a project developer, it is very difficult to predict how many hours a year a particular plant will be cut off the network.

Loan programmes for environmental investments

The State owned KfW Bank offers low interest loan programmes for renewable energy investments that can help project developers to optimize their cash flow.

KfW Umwelt Programm

The KfW Umwelt (Environment) Programme provides low interest loans to private companies. It finances max. 75% of investment costs, up to a maximum volume of € 10 million. Typically loans are given for a period of 10 years, but 20 years are also possible. Interest rates depend on the capital market and range at the lower end of capital market rates. Details are given in Table 4-5. In all cases, 4% of the credit volume are retained by the bank. For the cost calculations in this study we assume that the interest rates are 0.5 to 1.5% below average market rates. This is only a rough estimate, however, since the conditions depend on the financial circumstances of the individual borrower.

Table 4-5 German KfW Umwelt Programm loan conditions

Germany - Term		Effective interest rate (July 2006)
Usually max. 10 years, with max. 2 years free of redemption		4.21 – 7.26% (depending on credit worthiness)
May be changed to 12 years, 12 year free of redemption		4.51 – 7.56%
On request max. 20 years and 3 years free of redemption, if the technical and economic life-cycle of the investment is more than 10 years	Rate fixed for 10 yrs	4.38 – 7.43%
	Rate fixed for 20 yrs	4.53 – 7.60%
May be changed to 20 years, 20 years free of redemption		4.79 – 7.86%

The programme may be combined with the KfW ERP Programme up to 100% financing.

KfW ERP Programm

The KfW ERP Programme focuses on the support of Small and Medium Enterprises (SMEs) and favours investment in East Germany. The programme has a lower ceiling than the KfW Umwelt: € 500,000 in West Germany (Alte Bundesländer) and € 1 million in East Germany (Neue Bundesländer). SMEs can receive up to 75% financing, while other companies only receive max. 50%. Loans are given for 10 (West) or 15 years (East). The interest rates range at the lower end of the interest rates on the capital markets. For investments in East Germany, they are approx. 0.25% lower than in West Germany. Details are provided in Table 4-6. In contrast to the ERP Umwelt Programme, no agio is retained by the bank.

Table 4-6 German KfW ERP loan conditions

Germany - Term	Effective debt rate (July 2006)
West Germany (Alte Bundesländer): 10 yr, max. 2 yr free of redemption	4.22 – 7.19% (depending on solvency)
East Germany (Neue Bundesländer): 15 yr, max. 5 yr free of redemption, interest rate fixed for 10 yr	3.96 – 6.92% (depending on solvency)

For the cost calculations in this study, we assume that the projects can maximally benefit from both KfW Umwelt Programm (restricted to either € 10 million or 75% of investment, 4% agio) and ERP Programm (restricted to either € 0.5 million, or 50% of investment). In case additional debt is required, this is acquired under conventional market conditions. For both KfW schemes a 1.5% lower debt rate than for default market conditions is assumed. For the KfW Umwelt we use the 20 year fixed rate option, with 3 years free of redemption. Other financial parameters are kept the unchanged.

Other support programmes

There are a number of other support programmes that a relevant for RES investments in principle, but not applicable for the selected technology case studies:

- The KfW low interest loan programme “Solarstrom Erzeugen” finances investments in smaller PV plants up to € 50,000.
- The low interest loan programme “Sonderkreditprogramm Umweltschutz und Nachhaltigkeit” finances investments in agricultural biogas plants.
- The KfW low interest loan porgramme “Erneuerbare Energien” finances investments in renewable heat technologies.
- The Market Incentive Programme (Marktanreizprogramm) provides subsidies for investments in renewable heat technologies.

The CO_2 Building Rehabilitation Programme provides subsidies for energy efficient building modernisation. It also supports investments in solar thermal, PV and biomass heating installations.

Fiscal issues

The net corporate tax to be paid in Germany has both a federal component and a local component that is determined by the municipality (via the ‘Hebesatz’). This results in actual corporate taxes ranging from 33% to 41%. Here we take 38% as an average for Germany[5].

Except for biofuels, no specific tax deduction schemes exist for RES. There are also no RES specific tax depreciation schemes, but specific depreciation terms (see BMF Afa tables[6]):

- Wind power plants: 16 years
- PV plants: 20 years
- CHP plants: 10 years

Tax payers can choose between two depreciation methods: the straight-line method (linear) and declining balance method (degressive); a change from the declining-balance method to the straight-line method is permitted, but not vice versa. The declining balance method is normally limited to two times the allowable straight-line rate (double declining balance, with an overall maximum of 20%), but for the period 1/1/2006 to 31/12/2007 a three times higher rate is allowed (with a maximum of 30%).

Until 2005, a generic tax saving scheme existed that was not designed for renewable energies but made RES investment funds attractive to private investors. Initial losses from RES and other investment funds could be balanced against taxable income, thus reducing income taxes significantly. The scheme triggered a

[5] Based on a 25% federal corporate tax, a 5.5% solidarity tax, and an average ‘Hebesatz’ of 388% for germany. Source: KPMG International (2006)

[6] http://www.bundesfinanzministerium.de/cln_03/nn_3792/DE/Steuern/Veroeffentlichungen__zu__Steuerarten/Betriebspruefung/005.html

lot of private RES investments, but also led to the creation of funds that would never be profitable. The generic scheme was abandoned in October 2005.

Summary of financial assumptions for Germany (Alte Bundesländer)

Table 4-7 Summary of financial assumptions for Germany (Alte Bundesländer) (2006)

Germany Alte Bundesländer			Wind onshore	Wind offshore	Solar photovoltaic	Biomass CHP
Corporate tax		%	38% (German average)			
Fiscal depreciation	Type		Straight-line[a] Declining balance (single, double (max. 20%), triple (max. 30%) with or without a shift to straight-line			
	Period	yr	16	16	20	10
Debt measures	Type		a) KfW Umwelt Program (linear, 4% agio) b) KfW ERP Program (linear)			
	Period	yr	a) 20 (3 yr redemption free) b) 10 (2 yr redemption free)			
	Rate	%/yr	a) Default – 1.5% b) Default – 1.5%			
Tax measures			Declining balance (triple (max. 30%)) with shift to straight-line[a]			
Investment subsidiy		€/kW	-	-	-	-
Feed-in tariff	Initial	€/MWh	83.60	91.00	406	101.50
	Basic	€/MWh	52.80	61.90		
	Period of initial tariff					
	D (default):	yr	19.5	12.8		
	V (variant):	yr	16.7	12.8		
	Total duration of scheme	yr	20	20	20	20
Economic lifetime		yr	20	20	20	20

[a] The straight-line depreciation is assumed for the default case; the triple declining balance is assumed in the policy-support case. The triple declining balance is only applicable for projects started in 2006 and 2007.

4.4.2 France

RES-E support in France is dominated by a combination of two types of instruments: a feed-in tariff scheme and multiple tax relieves. For large RES-E plants (>12 MW) other than wind, a tendering scheme is in place. Additionally, different subsidy programmes are available on regional levels. National subsidy programmes have been significantly reduced since the introduction of the tax credit system in 2005.

The feed-in tariff scheme

The feed-in tariff scheme was introduced with Law 2000-108 (law on the modernisation and development of public services in the energy sector), and modified by Law 2005-781 (Programme on the orientation of energy policy): The law guarantees fixed feed-in tariffs to all renewable energy installations up to 12 MW and to wind power plants in reserved areas. Energy suppliers are obliged to buy the produced RES-E. Tariffs depend on renewable energy source and include a premium for certain technologies, see Table 4-8. Rates are corrected for inflation. For wind energy, a degression clause of 2% will be introduced in 2008. Higher rates are available in the overseas regions (DOM/TOM).

Table 4-8 Feed-in tariffs for selected technologies in France (mainland)

France - Technology	Duration (years)	Feed-in tariff 2006 (€/MWh$_e$)	Premium (€/MWh$_e$)
Wind onshore	15		n.a.
- initial tariff (year 1 – 10)		82	
- base tariff (year 10-15)		28-82	
Wind offshore	20		n.a.
- initial tariff (year 1 – 10)		130	
- basic tariff (year 10 – 20)		30-130	
Biomass (solid)	15		
reference tariff		49	up to 12
Solar PV	20		
- base tariff		300	
- building integrated		300	250

Tariff structure – Wind energy (Arrêté du 10 juillet 2006)

Reserved areas (ZDE)

The energy law of July 13th 2005[7] introduces the principle of reserved areas for wind energy (ZDE: Zones de développement de l'éolien). These ZDE are defined by the prefect, after proposal by the municipality. The choice is based on the

[7] Loi n° 2005-781 du 13 juillet 2005 de programme fixant les orientations de la politique énergétique

following criteria: wind resource, possibility of grid connection, and preservation of landscape, historical monuments, and protected sites. For each zone a minimum and maximum power output is defined. From July 14, 2007, the feed-in tariff is only granted to new wind energy plants if they are built in a ZDE.

Flexible tariffs

The tariffs for wind onshore and offshore were modified in July 2006[8]. They are fixed for the first ten years and depend on the annual production (full load hours per year) thereafter; the less production, the higher the tariff.

For onshore, 82 €/MWh are paid for the first 10 years (mainland France). During the following five years, the tariff ranges between:

- 28 €/MWh (≥ 3600 h/yr),
- 68 €/MWh (2800 h/yr), and
- 82 €/MWh (≤ 2400 h/yr).

Values in between are extrapolated.

The tariff for offshore is 130 €/MWh for the first 10 years. During the following ten years it ranges between:

- 130 €/MWh (for ≤ 2800 h/yr),
- 90 €/MWh (3200 h/yr), and
- 30 €/MWh (≥ 3900 h/yr).

Values in between are extrapolated.

Tariff structure – Biomass (Arrêté du 16 avril 2002)

For biomass, feed-in tariffs depend on the actual power delivered as compared to the guaranteed electrical power output (PG)[9]. The value of PG is guaranteed by the producer, either for the winter, or for the whole year. Depending on energy efficiency, a premium ("M") is granted.

If the actual power output is ≤ PG, the tariff is:

- RB x (0.575 + 0.5 x d) + M, if the plant is available 85% of the time, or more;
- RB x (0.15 + d) + M, if the plant is available less than 85% of the time

of which:

RB = reference tariff (49 €/MWh on the continent and Corsica, 55 in the DOM)
d = availability (between 0 and 1)
M = premium

[8] Arrêté du 10 juillet 2006 fixant les conditions d'achat de l'électricité produite par les installations utilisant l'énergie mécanique du vent telles que visées au 2° de l'article 2 du décret no 2000-1196 du 6 décembre 2000

[9] Arrêté du 16 avril 2002 fixant les conditions d'achat de l'électricité produite par les installations utilisant, à titre principal, l'énergie dégagée par la combustion de matières non fossiles d'origine végétale telles que visées au 4° de l'article 2 du décret n° 2000-1196 du 6 décembre 2000

M depends on the value of V = [valorized thermal energy + valorized electric energy]/energy output of boiler.

- if $V \leq 40$ % M = 0 €/MWh
- if V = 50% M = 5 €/MWh
- if V = 60% M = 10 €/MWh
- if $V \geq 70$% M = 12 €/MWh

Values in-between are extrapolated.

If the actual power output is > PG the formulae above are used with d = 0.15.

Tariff structure – solar photovoltaics (Arrêté du 10 juillet 2006)

The tariffs for solar photovoltaic installations were modified in July 2006[10]. They are fixed for twenty years of operation (300 €/MWh). For building integrated PV, a premium of 250 €/MWh is given.

Grid access and balancing

Regarding grid access, RES-E are treated the same as other energy technologies; if they comply with the grid code requirements, they are connected. In practice, connection procedures can be quite lengthy. The RES-E project pays the cost for the connection to the assigned grid connection point. It also bears the cost for project related grid reinforcement on the voltage level the plant is connecting to. If the network needs to be reinforced on higher voltage levels, the TSO pays the cost. So far, RES-E plants have no balancing responsibility, i.e. they don't pay balancing charges.

Tendering scheme

Law 2000-108[11] gives the government the possibility of setting up tenders if the RES-E development is not high enough for a specific RES and/or in a specific region. Several tenders have been published: onshore wind and offshore wind in 2005; biomass and biogas in 2005; biomass in 2006. In on of the last tenders for biomass and biogas plants >12 MW, 14 biomass projects with a cumulated capacity of 216 MW and one biogas project of 16 MW were selected. The projects had to be put into operation until January 1, 2007. The average contract price is 86 €/MWh.

Fiscal issues

The corporate tax in France is 33.33%.In case of a turnover exceeding € 7,630,000, an additional social surcharge of 3.3% is levied on that part of the corprate tax, exceeding € 763,000. In this study we use a fixed rate of 33,33%.

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[10] Arrêté du 10 juillet 2006 fixant les conditions d'achat de l'électricité produite par les installations utilisant l'énergie radiative du soleil telles que visées au 3° de l'article 2 du décret no 2000-1196 du 6 décembre 2000

[11] Loi n° 2000-108 du 10 février 2000, Loi relative à la modernisation et au développement du service public de l'électricité

Fiscal depreciation can be calculated according to the straight-line depreciation.The declining balance can be used as well. For assets with a useful life exceeding 6 years, the declining balance rate is calculated by multiplying the rate of the straight-line depreciation by a factor of 2.25.

Special depreciation of energy investments for enterprises
(L'amortissement exceptionnel pour investissements destinés à économiser l'énergie)[12]
Enterprises could write-off renewable energy investments within 12 months. As these investments had to be made 12 months before January 2007, this (potentially very effective) tax measure is not included in the analysis of this study. There are further tax measures that apply to individuals, but not to companies or municipalities (and hence not to the case studies in this report):

Tax credit ("crédit d'impôt") for private households
Private households installing renewable energy technologies can claim a tax credit of 50% of the capital costs (increased from 40% to 50% in 2006). The maximum credit volume is € 8000 per person. The credit has the disadvantage that it requires 100% pre-financing; therefore the financial benefit takes effect only after 1 year.

Reduced sales tax
Sales tax for residential renewable energy equipment (e.g. PV and solar thermal plants) is lowered to 5.5% in mainland France and 2.1% in DOM/TOM (compared to 19.6% general sales tax). A new tax credit for companies is expected for 2008

Further support measures

Public deficiency guarantee for SMEs ("FOGIME")
The FOGIME fund provides financial guarantees for bank loans to SMEs used (among others) for renewable energy investments. The maximum guarantee is €750,000, covering a maximum of 70% of the loan.

Financing via leasing ("Crédit-bail")
Special financing institutions (Sofergies) may provide financing to renewable energy projects via leasing. There are a number of other support programmes that a relevant for RES investments in principle, but not applicable for the selected technology case studies:

Sustainable development savings account (livret de développement durable)
Funds collected on these savings accounts will allow banks to finance loans with

[12] Arrêté du 27 décembre 2005 relatif aux matériels destinés à économiser l'énergie et aux équipements de production d'énergie renouvelables pouvant bénéficier d'un amortissement exceptionnel et modifiant l'article 2 de l'annexe IV au code général des impôts

attractive rates for energetic building renovation. The interest rate is currently 2.75%, and the interest is not subject to tax. The maximum credit volume is €6000. The eligible equipments are the ones eligible for the tax rebate.

ADEME programmes

ADEME gives investment subsidies for certain technologies: biogas, electricity production (small hydro, PV), geothermal energy, wood boiler, and solar heat (only under certain conditions). The amount of subsidy is defined by region.
Until 2005, ADEME offered up to 80% co-financing for RES investments to private households, enterprises and public entities. These subsidies have been reduced (and for private households abandoned) after the introduction of the tax credit scheme in 2005.

Summary of financial assumptions for France

Table 4-9 Summary of financial assumptions for France (2006)

France			Wind onshore	Wind offshore	Solar photovoltaic	Biomass CHP
Corporate tax		%	33.33%			
Fiscal depreciation	Type		Straight-line[a] Declining balance with 2.25 times the straight-line[b]			
	Period	yr	15	20	20	15
Debt measures			-	-	-	-
Tax measures			-[c]			
Investment subsidiy		€/kW	-	-	-	-
Feed-in tariff	Initial	€/MWh	82	130	-	-
	Basic	€/MWh	D: 82[d] V: 82	D: 110[e] V: 64	D: 300 V: 300	D: 61[f] V: 61
	Period of initial tariff	yr	10	10	-	-
	Total duration of scheme	yr	15	20	20	15
Economic lifetime		yr	15	20	20	15

[a] The straight-line depreciation is used for the calculation of the unsopported case. [b] The declining balance method is used for the case with policy support. [c] The accelerated 12 months depreciation for RES is not included in the analysis, as it is only relevant for investments prior to 1/1/2006. [d] Both the default (D, 2000 h/yr) and variant case (V, 2300 h/yr) have full load hours below the 2400 h/yr threshold. [e] Default: 3000 h/yr, variant: 3500 h/yr. [f] The tariff for biomass is based on an assumed availability of 85% below the guaranteed power production for both default (e.g. production during winter) and variant case. With an overall conversion efficiency of 90%, the full premium can be utilised.

4.4.3 Netherlands

The most important support instruments in the Netherlands in 2006 were the feed-in premium MEP and the tax deduction scheme EIA. They are complemented by low-interest loans available through green funds which are exempt from income tax. Premium tariffs in the MEP were put to zero in August 2006. A new premium scheme is introduced in 2008.

The feed-in premium MEP

As of 1 July 2003, the policy programme MEP (Environmental Quality of Power Generation) to support RES-E has been in operation. The MEP includes technology-specific premium tariffs that are paid for 10 years on top of the market price for electricity, with a maximum of 20,000 full load hours for wind power. Premium tariffs are adjusted every year. In May 2005 feed-in premiums for large scale pure biomass (>50 MWe) and offshore wind were temporarily set at zero. The reason was an expected lack of budget due to an anticipated strong development of especially offshore wind farms (available budget is partly financed through a fee for every electricity consumer, which is always defined one year ahead). The premium tariffs of the MEP scheme were put to zero in August 2006 by the Ministry of Economic Affairs for all newly applying projects, as the Ministry expected that the RES-E target for the Netherlands would be reached if all projects that already applied for the MEP would be realised. The MEP-scheme is replaced by a modified preium scheme, called SDE (Support scheme for Renewable Energy), as of 2008. The description below applies to the situation in the first half of 2006, and 2005 for wind offshore and large biomass respectively.

Table 4-10 Feed-in premiums as applicable in 2005/2006 in The Netherlands

Netherlands – Technology	Duration (years)	1 Jan 2005 to 30 June 2006 Premium (€/MWh)
Mixed biomass and waste	10	29
Wind on-shore		77[a]
Wind off-shore		97[b]
Pure biomass large scale > 50 MWe		70[b]
Pure biomass small scale 10-50 MWe		97[c]
PV, tidal and wave, hydro		97

[a] Restricted to max. 20,000 full load hours for onshore wind. Reduced to 65 €/MWh as of July 1, 2006 [b] Tariffs for offshore wind and large biomass were put to 0 €/MWh on May 10, 2005. [c] In 2006 the premium tariff was reduced to 60 €/MWh

There are no special premiums for biomass CHP. The biomass premium applies only for the electricity part. Alternatively, a biomass CHP could choose to receive the CHP-MEP, which is not to be confused with the MEP for renewable electricity.

The CHP-MEP is a completely independent instrument dedicated for CHP, but has no special incentive for biomass use. The standard CHP-MEP premium is around 20 €/MWh. Hence, no special incentive is given for combined heat and power production based on biomass and accordingly this combination is only rarely realized in the Netherlands. Some biomass power plants use a small part of heat production for treatment of the biomass feedstock.

Grid access and balancing cost

The Energy Research Centre of the Netherlands (ECN) regularly calculates the level of the feed-in premium MEP on behalf of the government. This calculation is based on a survey of the actual cost situation. Currently balancing cost of 6 €/MWh are assumed for wind energy.

Grid connection costs have to be covered by the project developer, while grid reinforcement has to be paid by the grid operator.

Fiscal issues

The corporate tax in The Netherlands is 29.6% (with 25.5% for the first € 22,689 of the earnings before taxation) (2006).

Fiscal depreciation can be calculated according to all approaches used in accordance with sound business practice (e.g. the straight-line depreciation, declining balance, et cetera). A change from the declining-balance method to the straight-line method is permitted, but not vice versa. Usually projects are written off linear over the period MEP is received, as this is considered the economic lifetime of the project.

Tax deduction scheme EIA

The EIA (Energy Investment Allowance) allows companies to deduct investments from their taxable profit. In addition to the usual depreciation rate, 44% of the eligible investment costs are deductible from the fiscal profit in the investment year. The net advantage of all projects under EIA is on average about 11 to 13% of the investment cost. The investment cost for which EIA can be granted was should be within the range of € 2,100 and € 108 million per company in 2006. Subsidies from other schemes should be deducted from the purchase or production costs, but operational subsidies need not be deducted, thus EIA can be combined with the feed-in premium MEP.

The government budget for the EIA is fixed annually. In 2006 and 2007 it was € 139 million. If the available EIA budget threatens to be insufficient, the Minister of Finance can limit the scheme or stop it temporarily, which has happened in the past.

The EIA applies to most RE technologies and to all technologies selected for our case studies:

- For wind, the maximum investment amount eligible under the EIA scheme is 1100 €/kW for onshore wind and 2250 €/kW for offshore wind.
- For onshore wind, on average about 85% of the investment is eligible.
- For CHP, an energetic efficiency of at least 65% is required (heat part is counted for 2/3).
- PV is generally eligible.

Low interest loans from green funds

Interest or dividends derived from funds investing for more than 70% in renewable energy or other 'green' projects are exempt from income tax and are thus attractive for investors. This results in loans at interest rates which are on average 1% below usual market interest rates. The funds are established and managed by banks and various conditions apply.

Projects are only eligible for a green fund if they have received a 'green statement' from the responsible authority. The minimum loan sum is € 22.689 and it can be restricted to a maximum of € 34.033.516. The maximum loan period is 10 years. Most renewable energy projects are eligible, amongst others those analysed in our cases, except for wind offshore. Biomass is restricted to clean wood and energy crops.

Summary of financial assumptions for The Netherlands

Table 4-11 Summary of financial assumptions for The Netherlands (2005/2006)

Netherlands			Wind onshore	Wind offshore	Solar photovoltaic	Biomass CHP
Corporate tax		%	29.6%			
Fiscal depreciation	Type		Straight-line Declining balance with or without a shift to straight-line			
	Period	yr	10	10	10	10
Debt measures	Type		Low interest loans from green funds (typical 1% below default rates)			
	Rate	%/yr	Def. – 1%	n/a	Def. – 1%	Def. – 1%
Tax measures			Tax deduction scheme EIA, 44% of eligible investment between € 2,100 and € 108 million			
	Typical eligible investment	%	85%	100%	100%	100%
	Additional restriction on investment	€/kW	1100	2250	-	-
Investment subsidiy		€/kW	-	-	-	-
Feed-in premium	Tariff	€/MWh	77[a]	97[b]	97	97[c]
	Period	yr	10[a]	10	10	10
Market value electricity		€/MWh	45-50	45-50	45-50	50-55
Economic Lifetime		yr	15	15	15	10

[a] Restricted to 20,000 full load hours. Premium reduced to 65 €/MWh as of July 1, 2006.

[b] Tariffs for offshore wind were put to 0 €/MWh on May 10, 2005. [c] Premium reduced to 60 €/MWh as of January 1, 2006

4.4.4 United Kingdom

The most important mechanism for financing renewable electricity projects in the UK is the Renewables Obligation, a quota scheme with tradable green certificates. Combined heat and power from biomass is also supported through the Enhanced Capital Allowance and the Bio-energy Capital Grant Scheme. Several further support instruments exist but do not apply to the selected cases.

Quota with Tradable Green Certificates (TGC): The Renewables Obligation

The primary RES-E policy mechanism in the UK is the Renewables Obligation (RO), which came into force on 1 April 2002[13,14] and is guaranteed until at least March 2027. The RO requires electricity suppliers to supply an increasing percentage of electricity from RES (excluding large hydro). This percentage increases until 2015-16, although the RO is guaranteed to remain in place until 2027 in order to give investment certainty also for projects commissioned in 2017 (see table below for annual targets). Electricity suppliers can meet their obligation:

- by surrendering Renewables Obligation Certificates (ROCs) to the electricity regulator Ofgem as evidence of renewable electricity generation;
- by paying the non-compliance 'buyout' price;
- by a combination of the two.

ROCs are issued for every 1 MWh of eligible renewable electricity generated from an accredited generating station. Separate ROCs are issued to generators in Scotland (SROCs)[15] and Northern Ireland (NIROCs)[16], but the three types of certificate are fully tradable and all can be used by any UK electricity supplier for compliance with the RO.

The non-compliance buyout price is adjusted annually in line with the retail price index. Payments are fed into a buyout fund that is recycled annually to electricity suppliers in proportion to the number of ROCs they surrendered in the compliance period. This provides an added incentive to meet the obligation by holding ROCs and keeps the trading price of ROCs above the buyout price (see table below for buyout price and an indicative value of ROCs). Annual compliance periods run from 1 April one year to 31 March the following year. ROC auctions are held each quarter.

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[13] UK SI 2002/914: Statutory Instruments SI 2002/914, The Renewables Obligation Order 2002 - Electricity, England and Wales (see www.opsi.gov.uk)
[14] UK SI 2005/926: Statutory Instruments SI 2005/926, The Renewables Obligation Order 2005 - Electricity, England and Wales (see www.opsi.gov.uk)
[15] UK SSI 2005/185: Scottish Statutory Instruments SSI 2005/185, The Renewables Obligation (Scotland) Order 2005 – Electricity (see www.opsi.gov.uk)
[16] UK SR 2005/38: Statutory Rules of Northern Ireland SR 2005/38, The Renewables Obligation (Northern Ireland) Order 2005 – Electricity (see www.opsi.gov.uk)

A medium-term target has been specified for 2016, target setting is planned for 2020, and duration of the scheme is guaranteed until 2027. This aims to provide long-term security for renewable energy investors. The RO is currently technology neutral and mainly develops the lowest cost technologies and does not stimulate promising technologies with still higher costs, as wave, tidal or photovoltaic energy. Biomass CHP receives ROCs only for the electricity part.

Table 4-12 RO targets, buyout prices & ROC values in the United Kingdom (status July 2007)[17]

United Kingdom	RES consumption target		Compli-ance to UK target	Buyout price	Value of recycled ROC		Total value of ROC to a supplier (buyout+recycle)		Average ROC auction price[b]
	EW,S[a]	N-I[a]			EW[a]	S[a]	EW[a]	S[a]	
Year	%	%	%	£/MWh	£/MWh	£/MWh	£/MWh	£/MWh	£/MWh
2002-03	3	-	59%	30	15.94	23.55	45.94	53.55	47.30
2003-04	4.3	-	56%	30.51	22.92	23.70	53.43	54.21	47.09
2004-05	4.9	-	69%	31.39	13.66	19.99	45.05	51.38	48.62
2005-06	5.5	2.5	76%	32.33	EW,S, N-I[a]: 10.21		EW,S, N-I[a]: 42.54		41.82
2006-07	6.7	2.6		33.24					
2007-08	7.9	2.8		34.30					
2008-09	9.1	3.0		Increases in line with retail price index					
2009-10	9.7	3.5							
2010-11	10.4	4.0							
2011-12	11.4	5.0							
2012-13	12.4	6.3							
2013-14	13.4	6.3							
2014-15	14.4	6.3							
2015-16	15.4	6.3							

[a] EW: England and Wales; S: Scotland; N-I: Northern Ireland

[b] Average ROC value at ROC auctions by the Non-fossil Purchasing Agency, www.nfpa.co.uk

Envisaged changes to the Renewables Obligation

The government currently considers to:

- Increase the level of the Obligation above the level previously announced to a maximum level of 20%.
- Introduce a mechanism intended to maintain Renewables Obligation Certificate (ROC) prices in a situation of ROC oversupply.

[17] Ofgem, 2007: Renewables Obligation: Annual report 2005-06; Ofgem, Ref. 36/07, 28 february 2007

- Band the RO to provide differentiated levels of support for different technologies:
  - Established technologies like sewage gas, landfill gas and co-firing of non-energy crops would receive 0.25 ROCs/MWh.
  - Reference technologies like onshore wind, hydropower and co-firing of energy crops would receive 1 ROC/MWh.
  - Post-demonstration technologies like offshore wind and dedicated regular biomass would receive 1.5 ROCs/MWh.
  - Emerging technologies like tidal and wave, solar-PV, geothermal, dedicated biomass burning energy-crops and advanced biomass conversion technologies (anaerobic digestion, gasification and pyrolysis) would receive 2 ROCs/MWh.
- Create separate obligations for the different technologies, with different buy-out prices and targets.

Changes to the scheme will be introduced at 1 April 2009 at the earliest.

Climate change levy exemption

Since 2002 renewable electricity and CHP has been exempt from the Climate Change Levy, which is a tax on electricity (excluding domestic and transport sectors), gas and coal. Until April 1, 2007 the CCL for electricity was 4.30 £/MWh (6.23 €/MWh)[18]; since that date an inflation correction is applied. Levy Exemption Certificates (LECs) are earned to prove exemption from the Climate Change Levy. The Climate Change Levy exemption has no influence on the production cost of renewable electricity and CHP, but on its price for industrial and commercial consumers and thus its competitiveness. If demand for LECs would drop below supply, the LEC value will drop. Furthermore, changes in climate change policies, e.g. the design of the European emissions trading system, might effect the level or overall existence of the CCL. In general, the benefits of the exemption are to be shared among producer, supplier, and consumer. For large-scale projects the producer might receive 80 to 90% of the LEC-value.

PPAs, RO purchase and balancing

Usually power and ROCs are sold within one long-term contract to one of the (few) electricity suppliers. In that case the electricity suppliers are responsible for balancing. One would normally deal with the balancing and settlement issues during negotiation of the power purchase agreement (PPA).

The electricity price one can achieve in a contract with electricity suppliers will be a combination of:

[18] UK SI 2001/838: Statutory Instruments SI 2001/838, The Climate Change Levy (General) Regulations 2001 (see www.opsi.gov.uk)

- the 'grey' electricity price (which may be fixed or based upon the System Sell Price / System Buy Price, the prices which are paid/charged in case of imbalance, defined by the Balancing and Settlement Code),
- the negotiated value of the ROC, which in turn depends on:
  - how well-covered the electricity supplier is in terms of ROC purchase
  - their perceived exposure to penalty charges for the duration of the PPA
  - price level of ROC buyout and recycled ROC
- the value of the Climate Change Levy Exemption Certificate (LEC, which often will be shared among producer, supplier, and consumer, see above)
- an assessment of the balancing and settlement risk against the PPA duration and negotiated value of the PPA, leading to a reduction in price, either per MWh or per time frame.

The shorter the time frame for the PPA, the greater the achieved overall electricity price, but the higher the financing risk. Here we will assume a PPA contract period of 15 year.

As a consequence of the above, only part of the value of the ROC or ROC buyout, the recycled ROC, LEC, and the electricity market value is transferred to the RES producer. The other fraction stays with the electricity utility and can be considered as a risk premium. The actual amount can be highly variable, depending on specific project characteristics and contract negotiations[19]. The producer can for instance negotiate a fixed price contract incorporating all of the above elements (low risk, low value), or make the decision to sell them by himself on the respective market places (high risk, potentially high value). The latter is not applicable for project financing as lenders will simply not be willing to finance the project. Often an intermediate model is used that provides enough securities for lenders by offering a floor price, but that also provides enough returns on equity by upside sharing. For this study we use this intermediate contract model with the following assumptions for the prices paid to the project developer/producer:

- 70 to 90% of the projected conventional wholesale electricity price, e.g. 35 to 40 £/MWh with prices for wind energy on the low-end, and for biomass-CHP on the high-end
- 90% of the ROC buyout value (32.33 £/MWh in 2006, adjusted for inflation during the project lifetime),
- 85% of the value of the recycled ROC (10 £/MWh in 2006, changing each year depending on the level of compliance to the renewables obligation),
- 85% of the LEC (4.3 £/MWh)
- A floor price equal to 70 to 75 £/MWh over the full project lifetime (in practice the floor price might change over time: from higher (e.g. 80 £/MWh) to lower values 60 £/MWh))

[19] Toke (2003)

For 2006 we derive under the listed assumptions an actual value of about 76 to 81 £/MWh, which would be higher than the assumed floor price. The 'risk premium' taken by the utility for the ROC and LEC is approximately 5 £/MWh, for the electricity volatility this is of the same order of magnitude.

Grid access

The developer bears the full cost for grid connection and grid reinforcement and these are sometimes the prohibitive factor. The cost estimates given here are very approximate (they could easily double in some circumstances). They are classified by the voltage level at the point of connection to the system operator. The costs exclude the switchgear, cables, transformers and other equipment within the project. Costs for reinforcement of the network at remote locations are also excluded from these estimates. The costs include capitalised charges to cover future operation and maintenance of the system operator equipment provided specifically for the project. System operator's often insist this is paid as a capitalised charge, typically 25% of the capital cost. Others allow this to be paid as an annual charge.

- Low Voltage: This is only feasible for very small generators connecting directly to the existing network. Costs will vary so widely that it would be misleading to state any here.
- 11 kV Grid connection equipment: £20,000 - £60,000
  Overhead line: £15,000 - £30,000/km
- 33 kV Grid connection equipment: £120,000 - £150,000
  Overhead line: £20,000 - £35,000/km
- 132 kV Grid connection equipment: £800,000 - £1,000,000
  Overhead line: Insufficient information

In our comparison, we will assume that grid integration costs are the same for all countries considered.

Bio-energy capital grant scheme

Capital grants are available for heat or combined heat and power from biomass. Grants cover up to 40% of the difference in cost compared to installing a fossil fuel alternative. Grants can be between £25,000 and £1 million. Round 3 of the Bio-energy Capital Grants Scheme was launched in December 2006. Defra intends to run further rounds of the scheme but has not announced them yet. Here we will assume that our 10 MWe biomass-CHP case replaces a gas-fired CHP unit and could receive the maximum capital grant of £1 million in 2006, or 100 £/kW.

Other technology specific support

Several further support instruments exist but are less relevant for the specified cases:

- The capital grant scheme provided grants for demonstration projects (Wind offshore, biomass, PV).

- Low Carbon Buildings Programme – capital grants for small installations in the built environment.
- Zero-interest loans for renewable energy projects conducted by SMEs up to £100,000 .
- Regional programmes in Scotland and Northern Ireland addressing communes and households.
- DEFRA Energy crops scheme – establishment grants for short rotation coppice and miscanthus.
- Marine Renewables Deployment Fund – tidal and wave energy demonstration projects.

Fiscal issues

The general corporate tax rate in the United Kingdom is 30%. This rate is assumed to be applicable to the companies that would be set up to develop the RES-projects in this study.

The default depreciation rule applying to renewable energy projects is 25% annually on the reducing balance basis. This applies for projects with an economic lifetime of less than 25 years. This is formulated as a capital allowance that is given to the investor. There could also be ways of qualifying for a 40% first year allowance if the special purpose company that owned and operated the plant qualified as a small to medium enterprise (SME), i.e. a company with fewer than 250 employees, and either annual turnover not exceeding € 50 million or a balance sheet totalling € 43 million, and which is not part of a larger enterprise that would fail these tests. This would apply for the projects under consideration.

Depreciation: Enhanced Capital Allowances

CHP components are eligible for increased depreciation under the Enhanced Capital Allowances (ECA). Businesses can claim up-front tax relief on their capital spending on designated energy-saving plant and machinery. The Energy Technology List (ETL) details the criteria for each type of technology, and lists those products that meet them. In order to qualify, biomass CHP has to obtain a Combined Heat and Power Quality Assurance Certificate (CHPQA), criteria depend on size and type of the CHP installation. Other large-scale RES are not included in the ECA scheme. 100% first-year Enhanced Capital Allowances allow the full cost of an investment in designated energy-saving plant and machinery to be written off against the taxable profits of the period in which the investment is made. All parts of a CHP unit despite the building housing the unit qualify for ECA. Here we will assume that 85% of the costs are eligible. The tax benefits of the 100% first-year ECA can not be carried forward to subsequent years, which makes it not interesting for a real project financing case without any provisions to deduct negative EBT (earnings before taxes) from other taxable income. This measure is hence more favourable for on-balance financing and is not incorporated in the analysis.

It has been announced by the UK Chancellor (March 2007) that it is intended to make wind turbines eligible in the near future, although no official confirmation is yet available on the ECA website (www.eca.gov.uk).

Summary of financial assumptions for the United Kingdom

Table 4-13 Summary of financial assumptions for the United Kingdom (2006)

United Kingdom £ 1 = € 1.44			**Wind onshore**	**Wind offshore**	**Biomass CHP**
Corporate tax		%	30%		
Fiscal depreciation	Type		25% reducing balance, with a 40% first year allowance for SMEs		
	Period	yr	15	15	15
Debt measures	Type		-	-	-
Tax measures	Type		ECA first-year allowance (tax deduction)		
	Rate	%	-	-	(100% [c])
Investment subsidy		£/kW	-	-	100
ROC-value (2006)[a]		£/MWh	90%*32+85%*10 =	37.6[b]	(54 €/MWh)
LEC-value (CCL)[a]		£/MWh	85%*4.3 =	3.7[b]	(5.3 €/MWh)
Market value electricity[b]		£/MWh	35-40	35-40	35-40
Floor price[b]		£/MWh	70-75	70-75	70-75
			(low-end)	(low-end)	(high-end)
Economic lifetime		yr	15	15	10

[a] Only part of the value of ROC and LEC are available to the project. The remaining 5 £/MWh is kept by the electricity supplier with the renewables obligation. Part of the LEC value can also be shared with the consumer. [b] Note that in actual PPAs these values can differ significantly. [c] The tax benefits of the 100% first-year ECA can not be carried forward to subsequent years. This measure is not incorporated in the comparative assessment, as it is not effective in our project finance case.

4.4.5 California

Renewable energy project developers in California can leverage a number of supporting measures, both from the State and Federal Government.

State support schemes

The main support instrument to promote renewable electricity at the state level is the **Renewable Portfolio Standard (RPS)**, which was implemented in 2002. The RPS is complemented with the production incentive scheme called the **Renewable Facilities Program (RFP)**. As part of the RFP the **Supplemental Energy Payments (SEP)** has the role to cover or mitigate above-market costs of meeting the RPS.

Federal support schemes

Main Federal support schemes include the **Production Tax Credit (PTC)**, the **Renewable Energy Production Incentive (REPI)** and the **Modified Accelerated Cost-Recovery System (MACRS)**.

In the following paragraphs, the different financing schemes will be analysed in more detail.

State support: Renewable Portfolio Standard (RPS)

California introduced a RPS, in 2002, pursuant to Senate Bill 1078. Under the provisions of this law, retail sellers of electricity were required to increase their procurement of eligible renewable energy resources to at least 20% by 2010[20]. As of January 1, 2003, each electricity distribution company had the obligation to increase its total sale of eligible renewable energy resources by at least an additional 1 percent of retail sales per year so that 20 percent of its retail sales are from eligible renewable energy resources by 2010[21]. In 2006 about 11% of the electricity was generated by RPS-eligible renewables.

Table 4-14 Targets under the Californian RPS

Year	Percent of total sales derived from renewable electricity
2003	At least 1 % above base load renewable use
2004-2010	At least 1 % above previous year
2010	20% of total sales
2020	33% of total sales

For purposes of setting annual procurement targets, the California Public Utility Commissions (CPUC) established an initial baseline for each utility based on the

[20] Originally the target was 20% by 2017. Senate Bill 107 of September 2006 accelerated to 20 percent by 2010

[21] SB 1078 (modified by SB 107) 399.15, (3) (b) (1)

actual percentage of retail sales procured from eligible renewable energy resources in 2001.

Eligible fuels and technologies

The eligible fuels and technologies are presented in the table below.

Table 4-15 Eligible fuels and technologies under the Calfornian RPS

• Biomass • Waste tire • Digester gas • Landfill gas • Municipal Solid Waste (MSW): Solid waste conversion facilities based on gasification techniques (MSW incineration is not eligible).	• Photovoltaic • Wind • Solar thermal • Geothermal • Existing small Hydropower (30 MW or less) • Ocean wave, ocean thermal, or tidal current

Classes of Retailers Covered

Subject to the provisions are:

- all investor owned utilities (IOU)[22],
- the electric service providers (ESP)[23], and
- the community choice aggregators[24] (CCA).

Supply contracts

The RPS requires a minimum of ten year contracts that are approved by the California Public Utilities Commission (CPUC) for qualifying renewable supplies with a provision that allows the CPUC to approve shorter-term contracts. Contracts are signed following competitive RPS solicitations held by the utilities covered by the RPS. The power purchase contracts to supply power between the utilities and the renewable energy producers are based on the energy price bid by the applicants in the solicitations, measured in cents per kilowatt-hour. The cost for the utilities may be lower than the market/contracted price as a Supplemental Energy Payment (SEP) becomes available to the utilities when the prices exceeds a 'market price referent'(MPR). More specifically for those contracts that go above the MPR, the system benefit fund pays the difference, provided that there is available funding under Senate Bill 1038 to pay for the above-market costs of such electricity through

[22] In California the three largest investor own utilities are the Pacific Gas and Electric (PG&E), the Southern California Edison (SCE), and the San Diego Gas & Electric (SDG&E)

[23] Public Utilities Code Section 394 defines an Electric Service Provider (ESP) as a non-utility entity that offers electric service to customers within the service territory of an electric utility (utility distribution company)

[24] Community Choice Aggregation (CCA) enables California cities and counties – or groups of cities and counties – to supply electricity to the customers within their borders. Unlike a municipal utility, a CCA does not own the transmission and delivery systems. Instead, a CCA is responsible for providing the energy commodity to its constituents – which may or may not entail ownership of electric generating resources. http://www.lgc.org/cca/docs/cca_energy_factsheet.pdf

the Supplemental Energy Payment (SEP) fund, collected from the "Public Goods Charges"[25].

The CPUC sets the reference price for the contracts which is applicable for each solicitation conducted by an electrical corporation. On December 2006 the CPUC adopted the Resolution E-4049 approving the 2006 Market Price Referents (MPR). This Resolution formally adopted the 2006 MPR values for a baseload proxy plant for the use in the 2006 RPS solicitations. The previously adopted benchmark cost for renewable energy was 53.7 US$/MWh.

Table 4-16 Adapted 2006 Market Price Referents (nominal US$/MWh)

Resource type[a]	10-year	15-year	20-year
2007 Baseload MPR	80.80	82.12	84.60
2008	80.14	82.31	85.19
2009	79.60	82.60	85.86
2010	79.65	83.33	86.91
2011	78.91	83.08	86.89
2012	79.62	84.21	88.21
2013	80.73	85.67	89.82
2014	82.30	87.47	91.69
2015	84.36	89.65	93.93

[a] Using 2007 as the base year, the Resolution calculates MPRs for 2008 – 2015 that reflect different project on-line dates.

Source : http ://www.cpuc.ca.gov/WORD_PDF/FINAL_RESOLUTION/63132.PDF

To satisfy their RPS requirements, California utilities used to contract a prevalence of wind and solar thermal electricity projects, as show by Table 4-17.

The California system currently does not separate the renewable energy attribute from the physical electricity (i.e. does not allow the creation of separately tradable Renewable Energy Certificates). Prices for renewable energy power are determined by competitive bidding and these prices are set in fixed-price, long-term contracts with individual electric utilities. Similar contracts are also prevalent for gray energy bought by utilities, as the CPUC limits the amount of power that investor-owned utilities can buy on the spot market to approximately 5 percent. As both renewable energy and grey energy are negotiated privately and price data are not made available, assessing the price impact of California's RPS is arduous.

[25] California Energy Commission administers SEP, but cannot assure that the State does not use the targeted funds for other purposes.

Table 4-17 Renewable energy under contract in 2007 (for contracts signed after 2002) in the Californian RPS

Technology	Capacity (MW)	
	min	*max*
Wind	2627	2989
Biogas	81	88
Biomass	218	263
Geothermal	767	1035
Small hydro	6	6
Solar thermal electricity	1452	2402
Solar photovoltaic	8	8
Total	**5159**	**6790**

Source: Database of Investor-Owned Utilities' Contracts for Renewable Generation, Contracts Signed Towards Meeting the California Renewables Portfolio Standard Target

Source : http ://www.energy.ca.gov/portfolio/contracts_database.html

Table 4-18 Contract Pricing and SEPs for 2007 Active Contracts (for contracts signed since 2002)

	Contracts	Total Capacity (MW)	
		Min	*max*
Total Active Contracts	76	5,159	6,790
New, Repower and Restart Active Contracts	64	4,598	6,230
Total Active Contracts Priced Above MPR	9	901	951
New, Repower and Restart Active Contracts Priced Above MPR	9	901	951
New, Repower and Restart Active Contracts That Require SEPs	6	330	380
% Total Above MPR	12%	17%	14%
% New, Repower and Restart Above MPR	14%	20%	15%
% New, Repower and Restart That Require SEPs	9%	7%	6%

Source: Database of Investor-Owned Utilities' Contracts for Renewable Generation, Contracts Signed Towards Meeting the California Renewables Portfolio Standard Target - http://www.energy.ca.gov/portfolio/contracts_database.html

The only publicly available price information in California is provided by Supplemental Energy Payments (SEP) applications. This data shows that only few applications for SEPs were submitted by the utilities[26] and it can therefore be inferred that most renewable energy prices in California have been at or below

[26] See the RPS contract database on http://www.energy.ca.gov/portfolio/contracts_database.html

MPR. Specifically, for contracts signed between 2002 and 2007, only about 12% of the contracts had a price that was higher then the market referent price. The operational status of all these contracts, however, remains "not on line".
However, the reform of some RPS' elements is under discussion: the Governor is considering to introduce new legislation (Senate bill 1036) passed by the California Senate and Assembly in September 2007 that will end the SEP process.

Considering that only a few contracts have gone above the MPR (which is levelled on price for energy generation with natural gas), and that none of such projects is currently operational, it can be argued that the Californian RPS did not lead to an increase in renewable energy (wholesale) prices *vis a vis* non renewable energy. Market observers have in fact highlighted that the main benefits of the support scheme has probably been the removal of institutional barriers, which hindered the development of renewable energy projects that made perfect economic sense, when utilities and developers, pre RPS, could select more familiar fossil-fuel-based projects.

State support: Renewable Facilities Program

Existing Renewable Facilities Program

The 'Existing Renewable Facilities Program' (1998 – present) was designed to help support the operation of existing (i.e. renewable projects that began operating before 26 September 1996) renewable technologies during the first years of the electric industry restructuring. The funds from the existing account were distributed monthly to renewable suppliers though a cents per kilowatt-hour (kWh) payment for eligible renewable electricity generation. The existing account was initially allocated US$ 243 million to be divided among three tiers:

- Tier 1 (biomass, waste tire and solar thermal) was allocated US$ 135 million
- Tier 2 (wind) was allocated US$ 70.2 million
- Tier 3 (geothermal, small hydro, digester gas, landfill gas and municipal solid waste) was allocated US$ 37.8 million

The amount of funds available in each tier declined each year as renewable generation facilities were expected to become more cost effective and therefore require less financial help to compete in an unregulated market.[27]

The maximum incentive price provided by this scheme was 15 US$/MWh, received by tier 1 suppliers in 1998 and for about half year in 1999. During this period tier 2 providers received a maximum of 10 US$/MWh while tier 3 received a maximum of 5.3 US$/MWh. Funds for all tiers were exhausted by June 2000.

New Renewable Facilities Program (SB 90, SB 1038, SB 1078)

[27] http://www.energy.ca.gov/renewables/existing_renewables/index.html

In its initial form the New Renewable Facilities Program provided a production incentive (US$/MWh) on top of the grey electricity price awarded through competitive auctions. Three auctions were held by the California Energy Commission in the period between March 1998 and June 2001. Production incentives were granted for a maximum of 5 years and ranged from 13.9 to 7.4 US$/MWh (see table below).

Table 4-19 New Renewable Facilities Program – summary of auction winning facilities

Technology	Number of projects	Capacity (MW)	Average incentive (US$/MWh)	Total funds committed[a] (million US$)
Biomass	2	11.30	13.5	3.8
Digester gas	1	2.05	13.9	1.1
Geothermal	4	156.90	12.8	75.6
Landfill gas	17	50.57	11.1	18.0
Small hydro	5	33.24	11.9	4.2
Wind	39	982.67	7.4	79.1
Total	**68**	**1,236.73**	**8.6**	**182**

[a] The total funds committed for winning bidders in the second and third auctions reflect both the loss opf potential bonusses for early on-line dates and 50% penalties for later on-line dates for those projects not yet on-line. The original conditional funding awards for winning bidders in the second and third auctions included potential bonuses for early on;line dates and did not reflect potential penalties for later on-line dates.

Source: Renewable Energy Program, 2006 annual report to the legislature, California Energy Commission, November 2006

With SB 1038 and SB 1078 the production incentives for new renewable facilities was combined with California's Renewable Portfolio Standard and was given the shape of the Supplemental Energy Payments (SEPs) which cover above-market costs of meeting the RPS.

State support: Investment subsidy ERP

The Emerging Renewables Program (ERP) provides incentives for grid-connected small wind (up to 50 kW) and fuel cells (up to 30 kW) using renewable energy fuels. Rebates (in $/W) for eligible renewable energy systems installed on affordable housing projects are available at 25% above the standard rebate level up to 75% of the system's installed cost.

State support: California Solar Initiative (CSI) – Performance Based Incentives (PBI)

Until 2006 the California Solar Incentive (CSI) provided an upfront, capacity-based payment for new PV and other solar electric systems. Starting January 1, 2007, incentives for all solar energy systems greater than 100 kW and below 1 MW are paid an incentive monthly, and for a period of five years, on the basis of the actual energy produced. This incentive is called Performance Based Incentives (PBI). An important criterium is that the installed solar capacity should serve on-site electrical load on an annual basis.

California Solar Initiative incentives will be disbursed based on the rates displayed below, which highlight a stepwise decrease as total market size increases.

Table 4-20 Large System Performance-Based Incentive Schedule (initially for systems 100kW or larger in size)

Step	Total installed per step (MW)	Incentive (US$/MWh)		
		Residential	Commercial	Government / non-profit
1	50	n/a	n/a	n/a
2	70	390	390	500
3	100	340	340	460
4	130	260	260	370
5	160	220	220	320
6	190	150	150	260
7	215	90	90	190
8	250	50	50	150
9	285	30	30	120
10	350	30	30	100

As of January 1, 2007, the programme had reached Step 2.

Thanks to the CSI, developers of solar photovoltaic projects can benefit of a secure income during the first 5 years of operation, currently 390 US$/MWh. Obtaining the CSI incentive does not preclude the use of the renewable energy produced to meet the Californian RPS obligation. Although being effective as of January 1, 2007, we will incorporate this measure in the cost assessment. The reference electricity end-use price is set at 131 US$/MWh[28].

[28] US EIA (2007)

Federal support: Renewable energy Production Tax Credit (PTC)

The PTC was created in the 1992 Energy Policy Act and provides an inflation-adjusted tax credit of 15 US$/MWh (1993 US$ and indexed for inflation) for electricity generated from qualifying renewable energy projects. Specifically production tax credit is applicable to the following technologies: wind, closed-loop biomass[29], open-loop biomass[30], geothermal energy, small irrigation power (150 kW – 5 MW), municipal solid waste, landfill gas, refined coal, hydropower, Indian coal and solar. Currently, the amount of the tax credit is 19 US$/MWh for wind, geothermal and closed-loop biomass; 10 US$/MWh for other renewable energy sources. For RE project initiators the duration of the credit is 10 years from the start of the project[31].

In the 11 years subsequent to the introduction of the PTC (1993 was the year before which qualified wind facilities became eligible for the credit) the annual production of electricity from wind has quadrupled in the US. The most rapid growth did not occur in the first five years (1994-1998) after the credit was created, but over the following six years (1999-2004). The PTC plays a key role in the business case for new RE power plants, as highlighted by the fact that interruptions of the PTC – which occurred when congress failed or delayed reauthorizing the act – and/or uncertainties about its renewal have been coupled with dramatic drops in RE investment in the US (see Figure 4-1).

For developers of large scale wind, CHP and PV project the financial benefit of the PTC are clear (see table below) and, as highlighted above, important. As the PTC credit can only be harvested by tax paying entities and as renewable energy project companies have often low tax liabilities, the PTC has induced/forced project developers to join forces with larger established enterprises, which provide the tax liability against which the PTC can be claimed. This resulted in more complicated structures for project financing and governance, with additional initial costs for renewable energy project developers in terms of time needed to find a potential partner and negotiate an agreement and associated administrative and legal costs.

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[29] Any organic matter from a plant which is planted for the exclusive purpose of being used to produce energy. This does not include wood or agricultural wastes or standing timber.
[30] All other types of biomass which are not planted for the exclusive purpose of being used to produce energy
[31] There is an exception for open-loop biomass plants placed into service after 10/22/2004 and before enactment of the Energy Policy Act of 2005 (8/8/2005). Such projects are eligible for the credit for a five-year period, only.

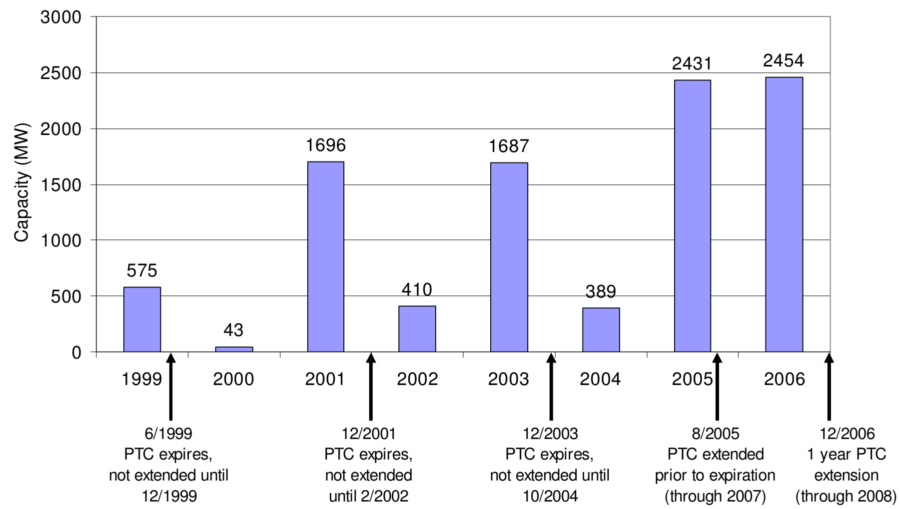

Figure 4-1 U.S. Wind energy capacity additions in the period 1999-2006 in the context of budget decisions on the PTC (www.awea.org)

Table 4-21 The federal production tax credit for selected technologies

	Tax credit (2006) (US$/MWh)
Wind[a]	19
Closed-loop biomass CHP	19
Open-loop biomass CHP	10
PV[b]	0

[a] The PTC reduces the cost of wind power by roughly one-third (~ 2 cents/kWh). Scheduled for a Public Hearing Before the Senate Committee on Finance on March 16,2005. Prepared by the Staff of the Joint Committee on Taxation.

[b] Note that solar facilities placed into service before December 31, 2005 were eligible for this incentive[32].

Federal support: Other technology specific support

Renewable Energy Production Incentive (REPI)[33]

The Renewable Energy Production Incentive (REPI) program was created by the Energy Policy Act of 1992, and amended in 2005 to provide production incentives for electricity generated and sold by a qualified renewable energy facility owned by a State or non-profit electric cooperative. Incentive payments of 15 US$/MWh (1993 US$ and indexed for inflation) for the first ten year period of operation, subject to the availability of annual appropriations in each federal fiscal year of operation.

[32] www.dsireusa.org
[33] www.dsireusa.org

Eligible fuels and technologies

Table 4-22 Eligible fuels and technologies under REPI

Tier 1	Tier 2
• Solar • Wind • Geothermal (with certain restrictions as contained in the rulemaking) • Closed-loop (dedicated energy crops) biomass technologies to generate electricity • Ocean (including tidal, wave, current, and thermal) • Fuel cells using hydrogen derived from eligible biomass	• Open loop biomass such as o Livestock methane o Landfill gas

Annual REPI incentive payments are subject to availability of appropriate funds. The Department of Energy can make no commitment for payment of REPI incentives beyond the funds obligated in each fiscal year. This uncertainty could prevent the stimulation of new renewable generation and thus influence the effectiveness of the scheme.

If there are insufficient appropriations to make full payments for electric production from all qualified facilities for a fiscal year, 60% of appropriated funds are to be assigned to facilities that use tier 1 fuels and technologies; while the remaining 40% is allocated to tier 2 facilities. Historically funds assigned to tier 2 were sufficient to finance all requests only for the first two years of REPI operations (1994 and 1995), while funds assigned to tier 1 projects were able to meet the requests of funds in full until year 2003. Currently, as the growth in requests outstripped appropriations, available funds are only able to cover a decreasing proportion of requests.

Energy Tax Act (Busines energy tax credit[34])

The Business Energy tax Credit is a tax credit available for households and businesses purchasing alternative energy equipment. For businesses, the tax credit was 10% for investments in solar, wind and geothermal. This credit was in addition to the standard 10% investment tax credit, available for all types of equipment. The tax credit for wind energy expired in 1985. The 10% business energy tax credit for solar and biomass was eventually made permanent in the Energy Policy Act of 1992. The Energy Policy Act of 2005 (H.R. 6) expanded the business energy tax credit for solar and geothermal energy property to include fuel cells and microturbines installed in 2006 and 2007, and to hybrid solar lighting systems installed on or after January 1, 2006. These provisions of the tax credit were later

[34] www.dsireusa.org

extended through December 31, 2008, by Section 207 of the Tax Relief and Health Care Act of 2006 (H.R. 6111). For eligible equipment installed from January 1, 2006, through December 31, 2008, the credit is set at 30% of expenditures for solar technologies, fuel cells and solar hybrid lighting; microturbines are eligible for a 10% credit during this two-year period. For equipment installed on or after January 1, 2009, the tax credit for solar energy property and solar hybrid lighting reverts to 10% and expires for fuel cells and microturbines. The geothermal credit remains unchanged at 10%.

Table 4-23 The tax credit under the energy tax act for selected technologies

	Tax credit for eligible equipment installed from January 1, 2006	Tax credit for eligible equipment installed on or after January 1, 2009
Wind	expired	expired
Biomass	expired	expired
PV	30%	10%

Public Utility Regulatory Policies Act (PURPA)

This law created a market for non-utility electric power producers forcing utilities to buy power from these producers at the "avoided cost" rate which the cost the electric utility would incur were it to generate or purchase from another source. Generally, this is considered to be the fuel costs incurred in the operation of a traditional power plant. PURPA contained also a provision that required local utilities to purchase excess power from industrial companies that produced electricity as a by-product of heat production in co-generation units. Although a federal law, the implementation was left to the States. However, in many states only a little was done.

Renewable Energy Systems and Energy Efficiency Improvements Program (USDA)[35]

The Renewable Energy Systems and Energy Efficiency Improvements Program has been created with the 2002 Farm Bill (Section 9006) by the U.S. Department of Agriculture (USDA) to make direct loans, loan guarantees, and grants to agricultural producers and rural small businesses to purchase renewable energy systems and make energy-efficiency improvements. Funds were appropriated for the financial year 2002 until the financial year 2007.

Eligible renewable energy projects include wind, solar, biomass and geothermal; and hydrogen derived from biomass or water using wind, solar or geothermal energy sources. The maximum grant award is 25% of eligible project costs up to

[35] www.dsireusa.org

US$ 500,000 for renewable energy projects and up to US$ 250,000 for energy efficiency improvements. Assistance to one individual or entity is not to exceed US$ 750,000. The minimum grant request is US$ 2,500 for renewable energy projects and US$ 1,500 for efficiency projects.

Under the guaranteed loan option, funds up to 50% of eligible project costs (with a maximum project cost of US$ 10 million) are available. The minimum amount of a guaranteed loan made to a borrower is US$ 5,000. Under this program it is allowed to combine a grant and guaranteed loan. However it can not exceed 50% of eligible project costs, and the applicant or borrower is responsible for having other funding sources for the remaining funds.

The maximum percentage of guarantee ranges from 70% to 85% depending on the loan value; the percentage for a given project will be negotiated between the lender and the Rural Business-Cooperative Service. The interest rate will be negotiated between the lender and the applicant and the repayment term must not exceed 30 years for real estate, 20 years for machinery and equipment, and seven years for working capital.

The USDA has implemented this program through a Notice of Funds Availability (NOFA) for each of the last four years. The latest round of funding was made available in March 2007 and is available in the form of grants, guaranteed loans, and combined guaranteed loans and grant applications.

Grid access and balancing costs

One of the most significant obstacles to renewable project development in California was the expensive cost for connection between new major renewable resource areas and distant utility high-voltage power grids. An additional significant cost for renewable energy suppliers were the balancing costs and penalties charged by grid operators. Historically transmission cost recovery rules, established by the Federal Energy Regulatory Commission (FERC), required renewable project developers to pay fully for transmission connections to utility high-voltage grids, even if their project was the first of several projects that eventually would use such connections. As a result, many smaller projects remained on the drawing boards waiting for others to fund the transmission projects. In 2006 the California Public Utilities Commission (CPUC) adopted a decision authorizing the utilities to initially pay for the needed transmission projects, charge renewable generators for transmission service for their share of the costs under rates approved by FERC, and recover the reasonable remaining costs from customers[36].

[36] A part from the grid access costs there is also a more practical obstacle as the significant congestion in the queue determined by the many people in line for grid access.

Regarding the balancing costs, the Scheduling Coordinator (SC) of a renewable energy project can either:

- make its best forecast of energy production and schedule it in the Day-Ahead or Hour-AheadMarket, or
- participate in the Participating Intermittent Resource Program (PIRP), where the energy generation forecast is used as the energy schedule in the Hour-Ahead Market.

In practice the PIRP program is advantageous to renewable energy operators as it allows them to schedule energy in the forward market without incurring in imbalance charges when the delivered energy differs from the scheduled amount. Specifically participants in the PIRP program agree to pay a small forecasting service fee (US$ 0.10 per delivered MWh) toward forecasting services developed for the Independent System operator in California (CAISO). The hourly deviations are calculated versus the forecasted delivery and are used to calculate a monthly average of energy imbalances. As the forecast of energy production is, on average, accurate, the cumulative amount of imbalance energy charges at the end of the month is a relatively small.

Power purchase agreements (PPAs)

As discussed above, California's investor-owned electric utilities are required by law to gradually ramp up their use of renewable energy. This principle drives the utilities to launch solicitations inviting all interested developers of renewable energy projects to submit their bids. Solicitations are generally made for 10, 15, or 20 year contracts. In the state of California under the RPS, the Renewable Energy Certificates (RECs) are bundled to their underlying power. Currently, California utilities can only comply with state RPS requirements by purchasing renewable energy directly from eligible renewable generators. Utilities cannot satisfy RPS requirements by purchasing RECs, which are separate from the underlying renewable energy production and sold as a separate commodity. However, the California Public Utilities Commission (CPUC) is considering the possibility of allowing California utilities to purchase tradable RECs to meet the RPS requirements.

Investment criteria

Rate of returns for renewable energy investments vary according to market conditions and the risk characteristics of the proposed project. For large scale wind projects in California required Return on Equity had varied between 12% and 18%. In the model used by the California Energy Commission to calculate the Market Price Reference (31/5/2007), and utilized for draft resolution E-4118 (for MPR 2007), the CEC makes the following assumptions:

- Debt: 50% (source: D.05-12-042, Findings of Fact 22, adopted)
- Equity: 50%
- Cost of debt: 7.72%
  Cost of Debt (industrial firms) = risk free rate (20 year T-Bill) + risk premium (mid point between BBB & B+)
- Cost of equity: 13.28%
  Cost of Equity = risk free rate (20-yr Tbill) + risk premium (equity) + mid-cap risk premium (equity)
- WACC: 8.93%
  Weighted average cost of capital = (Cost of Equity x Equity %) + (Cost of Debt x (1-tax rate) x Debt %)

Fiscal issues

In the US a variety of federal, state and local taxes can be charged. This depends on the fiscal and legal entity of the company structure. Here we will assume an average federal corporate tax rate of 35%. For California we will take the 2006 tax rate of 8.8% ('C-corporation'). State and local corporate taxes are deductible from the gross income in the calculation of federal corporate taxes.

Both on the federal and California-state level, the straight-line method is the default way of depreciation, albeit that other can be used under certain conditions. As part of the RES support scheme, solar PV and wind energy can be depeciated according to the 5 year MACRS approach for the federal taxes. For CHP a 15 year Modified Accelerated Cost Recovery System (MACRS) depreciation as applicable for industrial steam and electric generation and/or distribution systems will be used for the federal tax calculations.

California has excluded the depreciation under MACRS for the determination of state corporate tax levels, with some exceptions. At the state level the 150% decling balance is assumed. For the depreciation term we will use the economic lifetime, although specific regulations do apply in some cases.

Summary of financial assumptions for California

Table 4-24 Summary of financial assumptions for California (2006)

USA-California **1 US$ = € 0.79**		**Wind onshore**	**Solar photovoltaic**	**Biomass CHP**
FEDERAL				
Corporate tax	%	35%		
Fiscal depreciation	Type	Straight-line		
	Period	15 yr	15 yr	15 yr
Tax measures	PTC	19 US$/MWh 10 yr	not applicable (only solar facilities placed into service before December 31, 2005, are eligible)	19 US$/MWh (closed-loop) 10 US$/MWh (open-loop) 10 yr[a]
	Fiscal depreciation	5 year MACRS	5 year MACRS	15 year MACRS
	EPA	Expired	30% tax credit	Expired
Production incentive	REPI	Not applicable to our case	Not applicable to our case	Not applicable to our case
Grants and guaranteed loans	Renewable Energy Systems and Energy Efficiency Improvements Program	a) Grant award up to 25% of eligible project costs up to US$ 500,000. Minimum grant request is US$ 2,500. b) Guaranteed loan up to 50% of eligible project costs (with a maximum project cost of US$ 10 million). Minimum amount of a US$ 5,000. c) Combination of grant and guaranteed loan, not exceeding 50% of eligible project costs. Assumed not to be applicable to the type of investors assessed in this study.		
CALIFORNIA				
Corporate tax	%	8.8%		
Fiscal depreciation	Type	150% declining balance over 15 year		
	Period	15 yr	15 yr	15 yr
Tax measures		-		
Obligation	RPS/SEP	Renewable Portfolio Standard (RPS) / Supplemental Energy Payments (SEP)		
Market price referents (2007)		80.80 US$/MWh (10 yr); **82.12 US$/MWh (15 yr)**; 84.60 US$/MWh (20 yr)		
Production incentive (PBI)		-	390 US$/MWh for 5 year[b]	-
Economic lifetime		15 yr	15 yr	15 yr

[a] 5 years for open-loop biomass plants placed into service after 10/22/2004 and before enactment of the Energy Policy Act of 2005 (8/8/2005). [b] Although effective as of January 1, 2007, this policy measure is included in the assessment for 2006. The PBI aims to the reduce final consumption of electricity with a reference price of 131 US$/MWh (2006).

4.4.6 Québec

The Canadian renewable energy support is characterised by a mix of federal and provincial support schemes. The most important instrument for wind energy on federal level is the ecoENERGY direct production incentive. As an example for an additional support scheme on provincial level, the tendering scheme for wind energy in Québec will be described.

The federal ecoENERGY direct production incentive

The ecoENERGY for Renewable Power entered into force in April 2007[37]. Eligible RES-E projects are offered a production incentive of 10 CAN$/MWh on the produced electricity for 10 years. Eligible technologies include wind energy, certified hydropower, certified bio-energy and solar photovoltaics. Geothermal, tidal and wave energy are included, but at the start of the programme the eligibility criteria were not yet defined. The programme aims to stimulate the production of 14.3 TWh of renewable electricity over 4 years (2007-2011). It replaced the Wind Power Production Incentive (WPPI) that was frozen in 2006. It is also applicable for wind projects commissioned between April 2006 and March 2007; these plants receive the incentive on the electricity produced after April 2007 for 10 years.

The maximum funding for a renewable energy plant is fixed before the commissioning of the project: The contribution agreements are based on expected power production levels and outline the maximum amount of incentive payable over the 10 years of the agreement, as well as the estimated annual production. Once an agreement is entered into force, funding for the following 10 years is set aside for that particular project. If a project is over-producing in a given year, unclaimed amounts from previous years of under-production may be paid up to the actual production. The funding ends when the total maximum eligible production has been reached or when the 10-year period has been completed. For onshore wind energy the maximum capacity factor level in the contribution agreement is set at 35%.

The ecoENERGY programme has a provision to avoid over-subsidising of RES projects. If the cumulative revenues per MWh exceed a standard threshold price (STP), the payment of the incentive is suspended. If this difference exceeds the programme incentive (set at 10 CAN$/MWh), the project even has to repay that part of the received incentive (see NRCan, 2007). For onshore wind energy the standard threshold value is currently set at 130 CAN$/MWh for projects below or equal to 10 MW, and 120 CAN$/MWh for projects larger than 10 MW. This methodology will be reviewed biennially.

[37] NRCan (2007)

The maximum contribution to an eligible recipient over the lifetime of the programme is CAN$ 256 million, the maximum contribution per project CAN$ 80 million. Eligible are businesses, municipalities, institutions and organisations operating a "low-impact renewable energy plant" (basically all RES-E excluding hydro).

To qualify for support, the project must have total rated capacity equal or above of 1 MW (with an exception for wind energy projects that were commissioned before April 2007 which must have a minimum capacity of 500 kW, consistent with the final year of the WPPI programme). Production from test wind turbines installed under the Canadian Renewable and Conservation Expense (CRCE) provision of the federal Income Tax Act, are not eligible for the incentive.

The tendering scheme for wind energy in Québec

The province of Québec has supported local wind technology manufacturing through two large utility tenders for wind power. Québec has excellent wind resources, a well developed grid, as well as large hydropower resources that can be used to balance with wind power production. A first tender of 1,000 MW of wind was released by Hydro-Québec Distribution, Québec's state-owned utility, in May 2003 and closed in June 2004. For the financial conditions in the reference year 2006, only this first tender is relevant.

The first call for tenders contained the following key requirements[38]:

- Projects must be installed on the Gaspé peninsula (a particular regional development area of Québec) between 2006 and 2012;
- Projects coming online in 2006 must utilize a minimum of 40 percent local content, increasing to 50 percent in 2007 and to 60 percent for 2008-2012;
- Bidders had to develop proposals in conjunction with wind turbine manufacturers.

Eight winning projects with a total capacity of 990 MW were selected (Table 4-25).

By winning the tender, the project developer is sure of an inflation corrected price for the produced electricity during an agreed contract period. The average cost of the electricity for the eight winning projects is 87 CAN$/MWh, with 65 CAN$/MWh as the average electricity price paid to the projects, 13 CAN$/MWh grid connection costs, and 9 CAN$/MWh balancing cost. The contracts with Hydro-Québec have a term of 20 years.[39]

[38] The following information is taken from Lewis and Wiser (2006) and Hydro-Québec (2006)

[39] The second tender of 2000 MW resulted in an average price of 87 CAN$/MWh, plus 13 and 5 CAN$/MWh for grid connection and balancing cost, respectively. In about three years, the cost of wind power in Québec increased by 18 CAN$/MWh. (www.hydroquebec.com)

Table 4-25 Winning projects of the first tender for wind energy in Québec (Lewis and Wiser, 2006; Hydro-Québec, 2006)

Project developer	Location	Capacity (MW)	Expected to be on-line
Cartier Wind Energy	L'Anse-à-Valleau	100.5	2007
Cartier Wind Energy	Carleton	109.5	2008
Cartier Wind Energy	Les Méchins	150	2009
Cartier Wind Energy	Montagne-Sèche	58.5	2011
Cartier Wind Energy	Gros-Morne I and II	211.5	2011/2012
Northland Power Inc.	St-Ulric / St-Léandre	150	2007
Northland Power Inc.	Mont-Louis	100.5	2010
Total capacity		**990**	
Average capacity factor		**36.6%**	

Transmission and balancing costs are covered by Hydro-Québec. The electricity price of 65 CAN$/MWh is given in 2007 prices, and is indexed to the development of the Canadian Consumer price index. With a 2.5% rate of inflation, this would largely correspond to an average 20 year fixed-price contract of about 83 CAN$/MWh (simple average, calculated without time preference, about 59 €/MWh), excluding grid connection and balancing costs. Including these costs, a total fixed cost of the projects would be about 111 CAN$/MWh (about 79 €/MWh). These average costs should be considered in the light of the high wind speeds: on average 3200 full load hours. The first projects have been commissioned.

Due to the involvement and commitment of the wind turbine manufacturer in the bidding process (who has to invest in production facilities the region once the contract has been awarded), it is expected that all projects will be realised. Another important element is that the contract price is indexed for inflation, changes in exchange rates and steel prices. By removing this price-risk from the developers and turbine manufacturers, Hydro-Québec contributes to the bankability of these projects and success rate of the scheme. Another advantage of tendering for multiple projects in one round, is that it allows the transmission system operator to optimise its design, planning and opetration of the electricity system.

A second tender of 2000 MW was issued in October 2005 and was open until September 18, 2007 (originally it was scheduled for April 2007). Projects from this round have to come online between 2010 and 2015. In total 66 bids by 25 project developers for 7724 MW of wind energy were received.

Grid connection and balancing costs

Wind energy projects generally have to pay for grid connection. Winners of the Québec tender do not pay grid connection and transmission costs, but the expected costs are used for bid evaluation. The tender also includes a balancing and complementary capacity service. Balancing costs have no effect on the bid selection.

Other support programmes

Almost all provinces have launched a number of incentives and measures to support increased use of renewable energy, including requests for proposals (British Columbia, Québec, Ontario), legislated renewable portfolio standards (Atlantic provinces), Standard Offer Programs (Ontario and British Columbia), or government procurement (Alberta, Ontario).

Other programmes (however, not relevant for the case study in this report) are for example:

- The Market Incentive Program (MIP) provided investment subsidies of up to 40% to energy distributors who would set up new project to deliver RES-E to their residential and small business customers. The programme ended March 31, 2006.
- The Renewable Energy Deployment Initiative (REDI) provided investment subsidies of 25% up to a maximum of CAN$ 80,000 for renewable heating installations. REDI ended on March 31, 2007.

Fiscal issues[40]

The corporate tax rate in Canada is related to the type of income, the type of corporation and the province or territory where the income is earned. The general federal tax rate is 38%. If this income is earned in a Canadian province, 10% will be rebated. With a surtax of 4% this results in a 29.12% federal tax rate. This tax rate can be further reduced by 7% in case no other preferential fiscal measures apply. For some companies reduced tax rates for the first CAN$ 400,000 do apply, but this type of tax reduction is not assumed to be applicable to the considered wind energy case. So, for resulting federal tax rate is 22.12%. This is increased by the provincial tax rate of Québec (9.90%), resulting in an overall tax rate of 32.02%. Fiscal depreciation is based on a deduction with the Capital Cost Allowance (CCA), on a declining balance, which is different for different asset classes. The maximum rate is given in the Income Tax Regulations. For the first year only half of the maximum rate can be deducted. Conventional electricity production is covered in several classes: class 2 (6% declining balance[41]) for electrical generating equipment, and class 48 (15% declining balance) for electricity generating combustion turbines (acquired on or after February 23, 2005). The 6% declining balance will be assumed to be valid as a default reference for the wind energy case.

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[40] Income Tax Act 1985, c.1. and Income Tax Regulations, C.R.C. c. 945, available at http://laws.justice.gc.ca/

[41] 8% after the 2008 budget

Class 43.1 and 2 accelerated depreciation

The Canadian Income Tax Regulations allow the accelerated depreciation of the investment cost of wind power plants and certain other RES (small hydro, PV, wave, tidal, geothermal, co-generation, certain waste categories)[42]. Class 43.1 in Schedule II to the Regulations provides in a CCA of 30% (declining balance), which is extended to 50% in Class 43.2 for investments in the period 2005 (23 February) to 2012 (including certain high-efficiency co-generation plants)[43].

Canadian Renewable and Conservation Expenses (CRCE)

CRCE covers certain expenditures associated with the start-up of RES projects eligible under Class 43.1 or 43.2, e.g. feasibility studies, negotiation and site approval costs. It also covers up to 20% of a projected installed capacity (or up to 1/3 of wind farms with the total installed capacity of up to 6 MW) of the installation of test wind turbines. Under CRCE, eligible expenditures are 100% deductible in the year they are incurred or can be carried forward indefinitely for deduction in later years. These expenditures can also be renounced to shareholders through a flow-through share agreement, providing the agreement was entered into before the expense was incurred. This fiscal measure is not assessed in the cost assessment in this study.

[42] CANMET (1998/2007)

[43] Federal Budget 2007 extended Class 43.2 eligibility to assets acquired before 2020.

Summary of financial assumptions for Québec

Table 4-26 Summary of financial assumptions for Québec (2006)

CAN-Québec CAN$ 1 = € 0.71			Wind onshore
FEDERAL			
Corporate tax		%	22.12%
Fiscal depreciation	Type		6% declining balance (3% in first year)
	Period	yr	20
Debt measures			-
Tax measures	Type		50% accelerated depreciation (25% in first year)
	Period	yr	20
Production incentive	Tariff	$/MWh	10 (ecoENERGY)[a,b]
	Period	yr	10
QUÉBEC			
Corporate tax		%	9.90%
Fiscal depreciation			Same as federal
Contract price	Tariff	$/MWh	Electricity price: 65 (+ inflation correction)[c] Balancing cost: 9 (Grid connection cost: 13)
	Period	yr	20[b]
Economic lifetime		yr	20

[a] Maximum of CAN$ 80 million per project and CAN$ 256 million per eligible recipient.

[b] Hydro-Québec will take 75% of the ecoENERGY incentive, resulting in an effective incentive for wind project developers in Québec of 2.5 CAN$/MWh.

[b] Result of tendering procedure for wind projects with average full load hours of 3200. The ecoENERGY production incentive is not included. Grid connection and balancing cost are covered by Hydro-Québec.The specific grid connection cost for these projects in Québec is not included in the comparative assessment in this study.

5 Comparative assessment

In this chapter the cost of renewable electricity (RES-E) production will be assessed for several technology and country combinations. The impact of generic and RES-E specific policy measures on overall levelised cost of electricity and cost of capital will be presented and discussed.

5.1 Generic financial assumptions

The summary tables presented and discussed in the previous chapter will be used as input to the cost assessment model (see Annex 2 for a short description of the model). For the comparative assessment the following generic financial parameters are assumed to be valid for all cases:

- Inflation rate: 2.5%/yr
- Default debt rate: 6%/yr
- Default debt term: 10 year for biomass-CHP and 15 year for the other technologies (unless specific schemes provide in longer debt terms, such as the 20 year German KfW programmes)
- Economic lifetime: 10 year for biomass-CHP and 15 year for the other technologies (unless specific schemes provide in longer periods of support, see summary tables in previous chapters)

Although these factors differ per country and technology, they are believed to be representative for the 2006 situation for the cases considered in this study. Other generic assumptions are:

- Debt reserves can be used to cover debt service requirements (the debt reserve is assumed to be zero at the start of the project)
- 100% tax loss carry forward is allowed (assumed to be indefinite, although some countries/states have restrictions, i.e. California 10 years)

As both options generally result in lower levelised cost of electricity, they are included in the analysis[1].

Other key parameters that determine the cost of capital are the after-tax return on equity (RoE) required by the equity-provider, and the debt term, debt rate, and minimum debt service coverage ratio (DSCR) required by the lender. As indicated above, we assume fixed values for both debt term and rate, unless specific support

[1] We assume project financing cases without any provisions to deduct negative EBT (earnings before taxes) from other taxable income, which favours tax loss carry forward arrangements.

schemes affect these parameters. For actual projects these factors may differ per project and country, but we will assume that the technical risk profile is the same for all countries and that similar power purchase agreements or feed-in tariffs can be arranged for a 10 to 15 year economic lifetime.

RoE and DSCR are considered to be technology and country specific. Table 5-1 lists the assumptions for these parameters. The figures are based on the discussion in section 2.4.3, several interviews with financial experts in the renewable energy arena, insight in project plans for projects in different countries, the scarce public literature sources, and an own assessment of the risk situation.

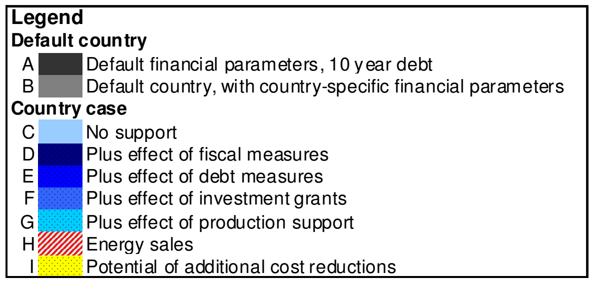
Table 5-1 Assumptions on required return on equity (RoE) and minimum debt service coverage ratio (DSCR) for selected combinations of countries/regions and technologies in 2006

Country	Renewable energy technology							
	Wind onshore		Wind offshore		Solar PV		Biomass CHP	
	RoE	DSCR	RoE	DSCR	RoE	DSCR	RoE	DSCR
Default country	15%	1.35	18%	1.5	15%	1.35	15%	1.8
Germany	9%	1.3	15%	1.4	9%	1.3	12%	1.7
France	10%	1.3	18%	1.4	10%	1.3	12%	1.7
Netherlands	15%	1.3	18%	1.4			15%	1.7
United Kingdom	15%	1.45	15%	1.6			15%	1.8
USA/California	12%	1.3			12%	1.3	12%	1.7
Canada/Québec	12%	1.3						

As a reference we will assume an onshore wind energy project with a RoE of about 12 to 15% and a DSCR of 1.3 to 1.35 (with known wind distribution profiles). For the default country (see Table 2-1) we will use the high-end value of this range. For the other countries risk premiums or discounts are assumed. Feed-in tariff systems with a stable policy context get the highest discount (e.g. Germany), whereas the inherent uncertainty of both feed-in premium and obligation schemes is reflected in high-end values for both RoE (Netherlands, UK) and DSCR (UK). The obligation scheme in the UK results in higher values for the DSCR by 0.1 to 0.2. For the bidding process in the schemes of California and Québec no additional premiums or discounts are assumed.

Offshore wind energy and biomass combined heat and power production have higher risk profiles as compared to onshore wind energy. Developing offshore wind energy projects is still associated with high risks during construction and operation. Here we assume that this results in a risk premium of 3 to 6% (as compared to the 12% onshore wind energy case) with the lower value assumed to be valid for countries with existing (remote) offshore wind energy projects and/or a strong government commitment towards offshore wind energy (UK, Germany). In the case of biomass CHP the supply of biomass is an important risk factor, resulting in higher values for the DSCR and in most cases higher values for the RoE.

In the following sections the results of the comparative assessment will be presented in graphs. The graphs represent for each technology the levelised cost of electricity for different countries under different conditions (bar A to C), as well as the effect of various generic or RES-specific support measures (D to H). For each country the graphs have the following bars (see for example Figure 5-1):



Default country – Levelised cost of electricity

A. The levelised cost of electricity (LCE) for the technology in the default country (30% corporate tax, linear fiscal depreciation over 10 year, 10 year debt term, 10 year economic lifetime), with default financial conditions as presented in Table 5-1.

B. Ibidem, but with country-specific financial conditions (see Table 5-1) and a debt term of 15 year. The difference between B and A is an indication for the change in the cost of capital when using the country-specific values for RoE and DSCR.

Country case - Levelised cost of electricity

C. The levelised cost of electricity for the technology in the specific country, without implementation of policy support measures for RES. The difference between C and B shows the effect of changing from the fiscal and economic settings of the default country to the one of the specific country.

Country case – Effect on levelised cost of electricity

D. The effect of fiscal measures on the levelised cost of electricity on the unsupported cost (e.g. tax deduction on investment in RES, RES-specific depreciation schemes).

E. The cumulative effect of debt measures on the above (e.g. government loans).

F. The cumulative effect of investment grants on the above.

G. The cumulative effect of production support on the above (e.g. feed-in tariff, feed-in premium, renewable electricity certificates, production incentive or tax credit).

H. The valuation of electricity sales, if applicable (e.g. not in feed-in tariff schemes).

I. An indication of the potential of additional cost reductions by assuming a RoE of 9% and a DSCR of 1.3, and an optimal debt term and economic lifetime (ranging from 15 to 20 years).

If bars D-H are omitted, no policy instruments are in place.

5.2 Onshore wind energy (20 MW)

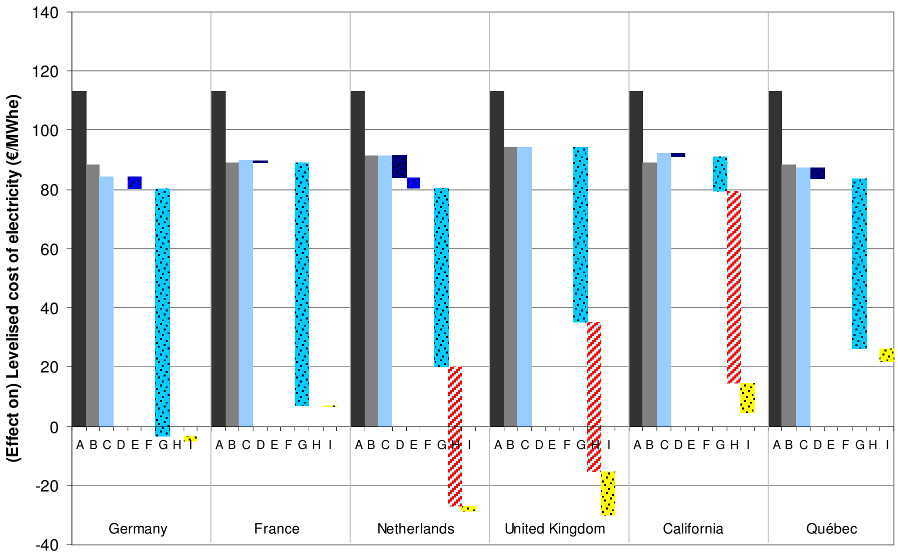


Figure 5-1 Levelised cost of electricity and effect of support schemes for onshore wind energy (**default, 2000 full load hours**)

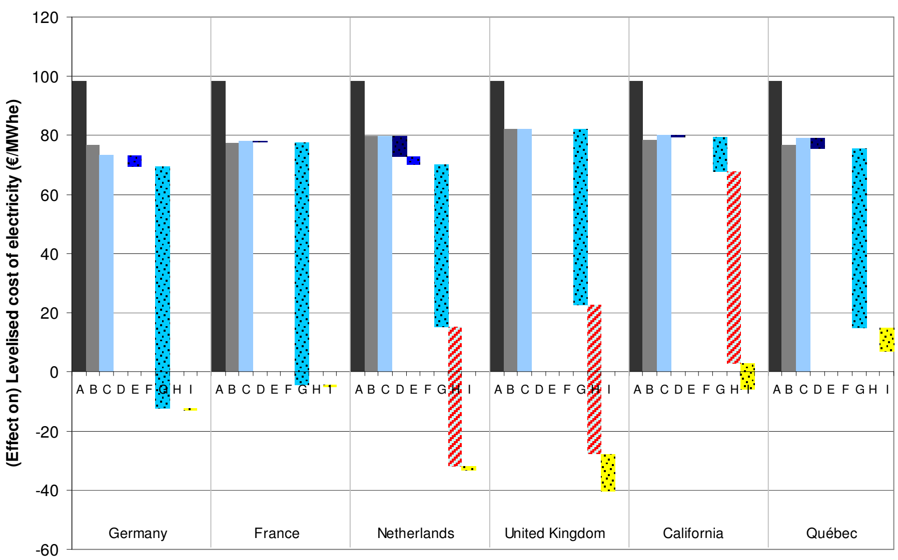


Figure 5-2 Levelised cost of electricity and effect of support schemes for onshore wind energy (**variant, 2300 full load hours**)

Legend
Default country
A Default financial parameters, 10 year debt
B Default country, with country-specific financial parameters
Country case
C No support
D Plus effect of fiscal measures
E Plus effect of debt measures
F Plus effect of investment grants
G Plus effect of production support
H Energy sales
I Potential of additional cost reductions

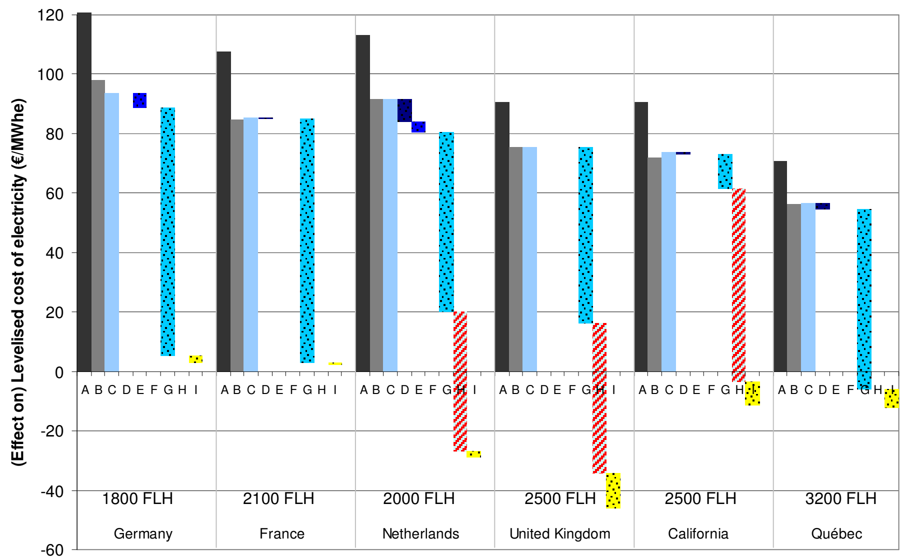


Figure 5-3 Levelised cost of electricity and effect of support schemes for onshore wind energy (**country-specific full load hours**)

Figure 5-1 and Figure 5-2 show the results for the assessment for onshore wind energy for both the default (2000 full load hours, FLH) and variant (2300 FLH) case. As some support schemes have been designed for the specific prevailing wind regimes in their country, Figure 5-3 shows the results for typical projects that were likely to be or have been developed in the year 2006.

Overall economic viability

The figures show that onshore wind energy projects are economically viable in all countries, albeit at different capacity factors. The feed-in tariff schemes in Germany and France take capacity factors (or average full load hours) into account, but in a different way. The French system is designed for support of wind energy projects in relative higher wind regimes. Projects are viable when they have full load hours of 2150-2200 hr and more (according to our model with the economic assumptions presented above). In the German scheme (which even incorporates turbine type and axis height in the calculation of the level of support) also lower wind speed regimes are being supported. Here the break-even point lies between 1900-1950 FLH.

The feed-in premium scheme in the Netherlands and the obligation scheme in the United Kingdom show that onshore wind energy was over-supported in 2006[2]. Both don't take variations in wind supply into account, albeit that the Dutch

[2] Assuming that market conditions in the UK stay constant over the lifetime of the project. The fact that this is uncertain, is the main reason for the higher values for both return on equity and debt service coverage ratio.

premium is only granted for the first 20,000 FLH. The Dutch scheme was modelled for a 2000 FLH reference wind turbine, assuming electricity market prices of 26 €/MWhe. Our model calculates a levelised cost of 20 €/MWhe, which would result in a profitable project at that electricity price. However, actual electricity prices in 2006 were in the range of 45-50 €/MWhe, resulting in significant over-support of this technology, even more for high wind regimes. For this reason, the 77 €/MWhe premium was reduced to 65 €/MWhe in July 2006. In 2007 it was decided to stop the support by setting the premium to 0 €/MWhe. The new feed-in premium scheme (SDE, active as of 2008) aims to correct for the variations in electricity market prices.

The obligation scheme in the UK has similar built-in effects: both the level of the ROC-buyout price, the Climate Change Levy and the level of the obligation are determined by government. The buyout price of the ROC of 32.33 GBP (about 46.5 €/MWhe) is an important element in the price-setting for renewable electricity. Its value, even when only part of it is forwarded to the project, is already large enough to make onshore wind energy projects viable. The calculated levelised cost of electricity range from 16 to 35 €/MWhe in the shown examples, whereas actual electricity market prices were about 50 €/MWhe in 2006. The obligation scheme does not differentiate amongst technologies, let alone amongst different wind regimes. Despite the high returns in 2006, the UK scheme has significant perceived risks, due to both the large impact of changes in government policies that could directly affect the value of renewable electricity, and the organisation of and developments on the RES-E and conventional electricity markets.

The support scheme in California has multiple elements, with the tendering process under the Renewable Portfolio Standard (RPS) being the most important contributor. The tariffs in the power purchase agreements that are negotiated between project developer and utility are not published. The electricity prices shown in the figures are the Market Price Referents that can be assumed to represent the upper-boundary of the actual negotiated prices for most cases. Under the assumptions in this study, onshore wind energy in California is only viable for higher wind speeds (break-even point at about 2400 FLH).

For Québec, the first tender for 1000 MW onshore wind energy resulted in projects with 3200 FLH on average; hence only Figure 5-3 is relevant to consider in this respect. With the assumptions presented above and in Table 4-3, the cost of such a wind project would be about 57 €/MWhe. The project will receive the electricity contract price of 74 CAN$/MWhe (for 20 year, excluding grid connection costs), which is corrected for inflation. This is added with 25% or 2.5 CAN$/MWhe of the ecoENERGY production incentive for 10 year. The combined effect (contract price, inflation correction and ecoENERGY) results in a levelised income of 85

CAN$/MWhe or 60.5 €/MWhe during 20 years. Fiscal measures add another 2.3 MWhe. This results in a negative levelised cost of electricity of about 6 €/MWhe.

Effect of key financial parameters

All countries show significant reductions in the levelised cost of electricity as compared to the default case (bar C compared to A in the figures), ranging from 15 to 25%. This is the effect of using lower values for the return on equity and debt service coverage ratio as applied by investors and lenders (bar B compared to A), reflecting the reduction in the perceived risks as a consequence of the national policies and the support measures and market conditions presented in bars D to I. The effect of changing from the fiscal regime of the default country to the one of the selected country is minimal in most cases (bar C compared to B). Changing the level of the corporate tax has limited effects on the levelised cost of electricity for most countries, as already shown in Figure 2-8, whereas conventional fiscal depreciation methodologies often involve straight-line (as in the default country), or declining balance depreciation.

Effect of support instruments: Fiscal measures

Fiscal measures can have a notable effect on the levelised cost of electricity. In the country cases both investment tax deduction schemes (e.g. NL), and accelerated or modified fiscal depreciation schemes (US and Canada, at the federal level) occur. The first year tax deduction in the Netherlands results in a reduction of the LCE by 7 to 8 €/MWhe.

Some fiscal measures have limited impact in our project finance case, as the fiscal losses of the project are not assumed to be deductable from other taxable income. If these were to be deductable (e.g. via arrangements that transfer tax losses to other corporations, or in corporate finance), overall levelised costs of electricity could be reduced. As an example the Modified Accelerated Cost Recovery System (MACRS) as applied in the US taxation at the federal level, has limited impact (0.7 €/MWhe) in our 2500 FLH California case with an LCE of 61 €/MWhe (Figure 5-3). If tax losses could be transferred, the LCE would be reduced to 53 €/MWhe, with a 7 €/MWhe contribution from the MACRS. This is a good illustration of the fact that different financing models are differently affected by fiscal measures.

The production tax credit (PTC) in the US reduces levelised cost by about 12 €/MWhe. As discussed before, the PTC has no effect on the leverage of the project, and hence does not reduce cost of capital. Due to the stop-and-go nature of the PTC in the past, this instrument was not considered by investors and lenders to be robust. In order to reap the tax benefit, project developers have to join forces with (large) companies with net taxable income, in order to benefit from the tax credit.

This increases the project cost and the cost of capital. The production tax credit is here positioned under production support (bar G in the figures).

<u>Effect of support instruments: Debt measures</u>

Both the Netherlands and Germany have debt measures with an overall reduction on levelised costs of about 3 to 5 €/MWhe. The Dutch debt measure is based on a tax exemption for investments in so-called Green Funds. Because of this tax benefit, the investors are satisfied with lower returns, and hence the fund can lend money at lower rates (typically 1% below market rates). In Germany the State owned KfW Bank offers special loan programmes with lower interest rates (e.g. 1.5% below market rates), long debt terms (up to 20 year), and a redemption free period (e.g. up to 3 year). The longer debt term has not only a direct effect on the levelised cost, but also an indirect effect: together with the 20 year feed-in tariff it increases the economic lifetime as applied by the investors of the project, resulting in lower levelised cost (this effect is incorporated in bar B in the figures).

<u>Effect of support instruments: Investment grants</u>

None of the schemes has investment grants for onshore wind energy. Several countries have used this instrument in the past in the early days of wind energy deployment. The investment tax deduction in the Netherlands implicitly acts as a kind of conditional investment grant. When the project is a generating income, the investment can be partially deducted from this income, and is typically used to repay part of the debt.

<u>Effect of support instruments: Production support measures</u>

It is clear that the production support schemes have the most prominent contribution in reducing the levelised cost of electricity for onshore wind energy in the cases considered. By adjusting the level of feed-in tariffs and feed-in premiums the economic viability of a typical project can be achieved. In tender schemes (Califiornia, Québec), the levels of the contract prices are determined by the market actors. In Germany, France and the Netherlands these levels are determined by government. The level of support under the UK obligation scheme is highly related to conditions set by government (e.g. ROC buyout price, overall obligation level).

The design of the scheme and the stability of the policy context directly affect the risk assessment of a project by investors and lenders. An attempt is made to quantify this effect in Table 5-1. For onshore wind energy the following issues contribute to the risk profile of a country:

- The 15 to 20 year support provided or negotiable in Germany, France, California and Québec sets the standard favourably for the applied economic lifetime of a project, whereas the 10 year premium support in the Netherlands and the inherent uncertainties in the UK obligation scheme result in lower applied economic lifetimes (e.g. 15 year) and higher levelised cost of electricity.

- For some types of support, the cost of the support can either be covered by the government budget, or by end-users via their electricity bill. The former has the risk of budget overruns and is more likely to be affected by changes in government (e.g. the investment tax deduction and feed-in premium in the Netherlands, production tax credit in the US). This adds to the risk profile of a country (see below).
- The success rate of the project development phase is an indication of the attitude of a country towards onshore wind energy and the way this is reflected in laws, regulations and institutional support.
- The flexibility of the support scheme towards changes in investment costs or market conditions is important for the number of projects that reach financial closure. The German feed-in tariffs are automatically declining each year, whereas historic turbine cost actually went up. The Dutch feed-in premium could in principle be adjusted each year to reflect changes in electricity market prices and technology cost. Whereas in the past several tender schemes in Europe have shown low success rates, the realisation of the projects from the first tender in Québec seems to be on schedule. The tender incorporated inflation, and changes in steel prices and exchange rates.

<u>Potential of additional cost reductions</u>
The last bar (I) in the figures is an indication of the potential of additional reductions in the cost of capital, by assuming an overall return on equity of 9%, a debt service coverage ratio of 1.3 and in some cases a debt term equal to the economic lifetime. For all countries additional cost reductions could be achieved, ranging from about 1 to 12 €/MWhe for the case with assumed country-specific full load hours (Figure 5-3). The cost reductions can mainly be achieved by reducing regulatory and financial risk. Additional reductions can be achieved by extending the support periods. For example, the relatively small figure for France could be increased by extending the support scheme for onshore wind energy from 15 to 20 year, even with lower feed-in tariffs.

The resulting level of the levelised cost shows the extent of under- or over-support of the schemes under more advanced conditions. In feed-in tariff and -premium schemes this can be corrected for by changing the tariff/premium levels. For obligation schemes this requires changes in the design of the scheme, e.g. by applying lower buyout prices (UK) or by introducing technology bands or technology premiums that reduce the generic cost of certificates.

Financial resources
The model calculates the lowest levelised cost of electricity at the given debt service conditions, by varying the equity share of the investment. For the country-specific cases, the result for most European countries is a debt/equity ratio of about 80/20% (75/25% for the Netherlands), whereas California and Québec show a higher share of equity: about 65/35%. For the US/California case this is a consequence of the PTC, which benefits the investor, but does not affect the project finance structure. For Québec, the assumed relatively low required return on equity (12%) reduces the cost of capital in favour of equity. In Germany, 9% is assumed, but there it has to 'compete' with the low interest rates of the state bank.

Figure 5-4 shows the origin of the revenues for the 20 MW onshore wind energy case with country-specific capacity factors (comparable to Figure 5-3). The figure shows the average annual required income to make the project viable over the economic lifetime of the project[3] (gross levelised cost times annual electricity production), and the financial resources for these revenues.

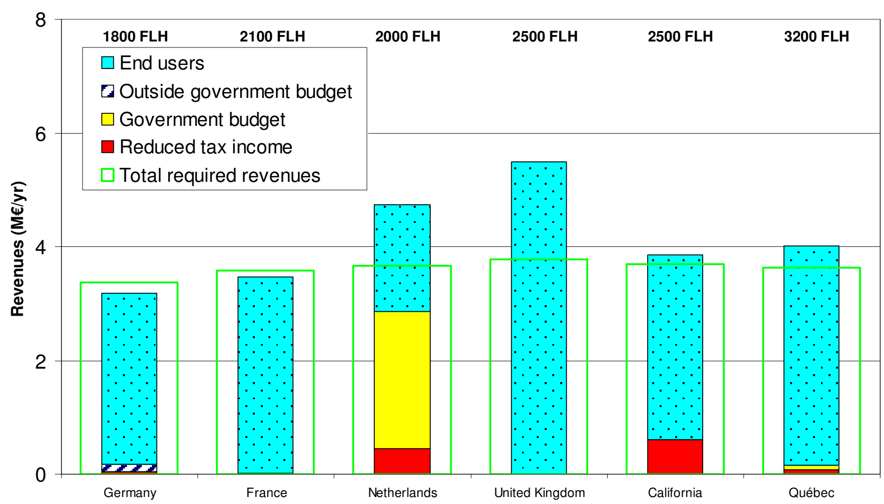


Figure 5-4 Financial resources for the 20 MW onshore wind energy case (**country-specific full load hours**)

The assumed investment of 24 M€ should be earned back by average annual revenues of 3.4 to 3.8 M€. The figure gives a breakdown of the financial resources for these revenues: a part that affects the government budget (via reduced tax income, or by direct expenditures on support schemes), a part that doesn't affect government budget (typically loan guarantees and/or low-interest loans), and a part

[3] Note that for Germany and Québec an economic lifetime of 20 year is assumed, and 15 year for the other countries (related to the design of the overall support scheme, see country summary tables in the previous chapter).

that is paid by end-users (via their electricity bill). It should be noted that not all revenues are equally spread over the economic lifetime of the project. For instance the investment tax deduction in the Netherlands can typically be claimed one year after investments have been made (about 2.6 M€ for this particular example).

The figure shows that most schemes are designed to have limited direct impact on the government budget, except for the Netherlands. Fiscal measures are important in the Netherlands, and in the US and to a lesser extent in Canada (where they are implemented at the federal level). The impact on the government budget and the related risk of budget overruns has resulted in stop-and-go policies in the Netherlands (both for the feed-in premium and the investment tax deduction) and is one of the elements contributing to the relative high cost of capital. The total end-user costs in the UK are in fact higher than depicted here, as part of the value of the ROC stays at the energy utility with an obligation.

5.3 Offshore wind energy (100 MW)

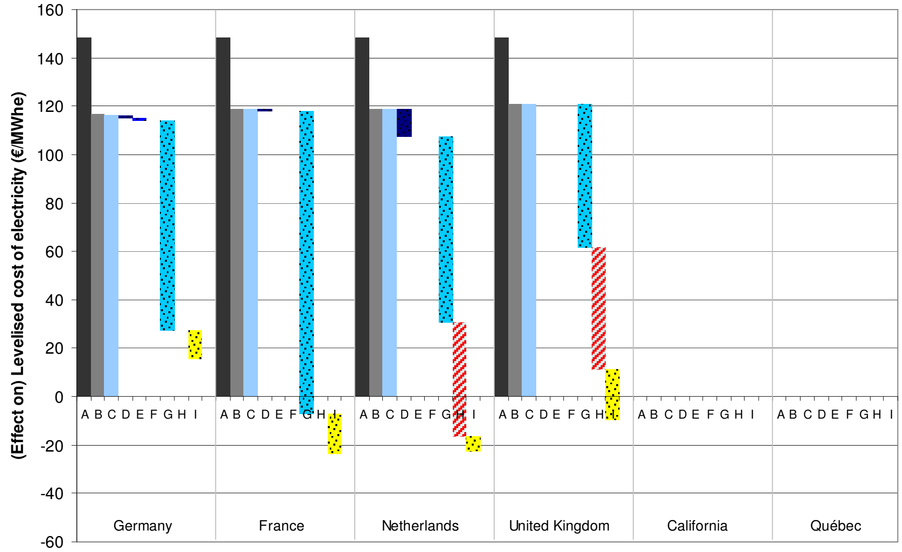


Figure 5-5 Levelised cost of electricity and effect of support schemes for offshore wind energy (**default, 3000 full load hours**)

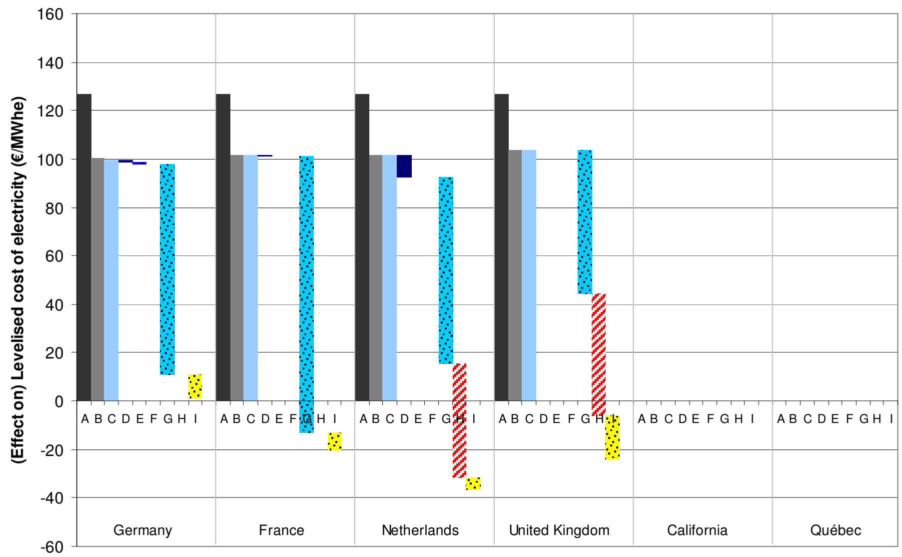


Figure 5-6 Levelised cost of electricity and effect of support schemes for offshore wind energy (**variant, 3500 full load hours**)

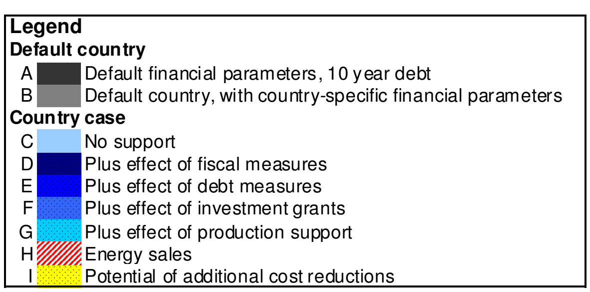


Figure 5-5 and Figure 5-6 show the results for the assessment for offshore wind energy for both the default (3000 full load hours, FLH) and variant (3500 FLH) case (2006 situation).

Overall economic viability

The figures show that offshore wind energy projects are economically viable for the variant case in all countries but Germany. For the lower default case, only France and the Netherlands enable viable projects (despite the higher assumed return on equity of 18%). The over-support in the Netherlands was a consequence of the higher than expected electricity market prices (see section 5.2). The premium was set to 0 €/MWhe at May 10, 2005 (so the figure actually shows the early 2005 situation). As the Netherlands didn't have a clear concession or exclusivity policy for offshore wind energy, project applications were put on hold for a long time. When this stopped, a huge number of project applications were received, with the tariff reduction as an immediate response. The stop-and-go nature of the policy support, and the fact that the licensing procedure does not show predictable outcomes, results in high regulatory risks for the project developer. Nevertheless, by 2008 two offshore wind projects are operational – one corporate financed and one project financed.

Despite the fact that Germany has no major offshore wind energy projects in operation, and that the level of policy support is insufficient to make projects viable, the risks of the German market are perceived to be lower. The German government is pro-actively trying to remove institutional and market barriers and market actors expect that feed-in tariffs will be increased to reflect market conditions. For instance, in 2006 the transmission system operators (TSOs) were made responsible for grid connection of offshore wind energy projects. This is expected to result in significant cost savings (see below), due to the different financing conditions of the TSOs and the fact that grid connection of projects will be combined.

The situation in the UK is also favourable for offshore wind energy: the government has ambitious plans for offshore wind energy and consequently has a similar pro-active approach as in Germany. The current design of the obligation scheme and the resulting market conditions, are not favourable for project financed projects in moderate wind regimes (see default case). Most projects are currently corporate financed. But the proposed introduction of differentiated support will likely change this.

For France no experience with offshore wind energy exists. Favourable sites with relative low seawater depths may be scarce.

<u>Effect of support instruments</u>
All countries show significant reductions in the levelised cost of electricity as compared to the default case (bar C compared to A in the figures), by about 20%. The reason is identical to the case for onshore wind energy, with an important impact from the longer economic lifetimes used as a consequence of the support schemes in place. Due to the development stage and higher technological risk of offshore wind energy, overall values for return on equity and debt service coverage ratio are assumed to be higher than for onshore wind energy.

The effect of the support schemes is similar to the situation for onshore wind energy, with some minor differences. For instance, in the Netherlands offshore wind energy was not eligible for financing from low-interest Green Funds. And in France, the period of support is extended from 15 years (onshore) to 20 years for offshore wind energy.

The investment cost for offshore wind energy projects has been increasing significantly in the past few years. Higher steel prices, and the high demand for onshore wind turbines in the US has resulted in scarcity and high prices for offshore wind turbines (project costs well above 3000 €/kW, as compared to the 2200 €/kW used for the assessment for 2006). The feed-in tariff and premium schemes can adjust their price levels at specific time intervals to accommodate for these changes in cost levels. The UK system is currently less flexible as changes in market design parameters can affect the viability of new and existing projects.

<u>Potential of additional cost reductions</u>
For all countries additional cost reductions could be achieved (ranging from 10 to 20 €/MWhe). Due to the development stage of offshore wind energy, risk prevails at all levels: technological, regulatory and financial. It is expected that overall investment costs can be significantly reduced by technological improvements on both turbine, foundation, grid and system integration. The same is true for the risks and associated cost of capital.

Here the effect of two additional policy support measures is illustrated: (i) making grid connection the responsibility of transmission system operators, and (ii) making meteo data available to project developers.

(i) Grid connection by transmission system operator
By making the transmission system operator (TSO) responsible for the grid connection of the offshore wind energy projects, the cost of capital can be reduced. The TSO will finance the project on its own balance sheet or will have access to cheap loans under favourable conditions. With grid connection investments being in the range of 400 to 500 €/kW (or about 20% of the total project cost, here

assumed to be 2200 €/kW (2006)), levelised cost can be reduced by more than 15 €/MWhe (3500 FLH case for the Netherlands), of which roughly 5 €/MWhe as a direct consequence of the reduced cost of capital. Also investment costs can be reduced: several wind projects could be jointly connected to one offshore grid, or wind energy projects could be combined with offshore electricity production from natural gas. These additional cost savings are estimated to be in the order of 5 €/MWhe or more, due to the higher utilisation rates of the offshore grid[4].

(ii) Make meteo data available to project developers
Wind resource data are often not available for offshore situations. For lenders this adds to the risk of the project. If governments arrange the availability of monitored meteo data (e.g. by investing in offshore meteo platforms) loan conditions could be improved, e.g. a reduction of one or more percent points of the interest rate, and a reduction of about 0.1 in the DSCR (e.g. from 1.4 to 1.3). When we apply these assumptions to the 3500 FLH Netherlands case, levelised cost of electricity is reduced by more than 2 €/MWhe.

Financial resources
As compared to onshore wind energy projects, the debt/equity ratio for offshore projects is shifted slightly towards more equity: ranging from 75/25% to 70/30%. This is notably a consequence of the higher debt service requirements.

The distribution of the financial resources is is similar as depicted for the onshore wind energy cases. The 100 MW (3500 FLH) case with an investment of 220 M€ requires annual revenues of about 35 M€.

[4] See for example the Supergrid proposal from Airtricity (http://www.airtricity.com/ireland/wind_farms/supergrid/) and the POSEIDON vision of Econcern (www.poseidonenergy.com).

5.4 Solar photovoltaic energy (0.5 MW)

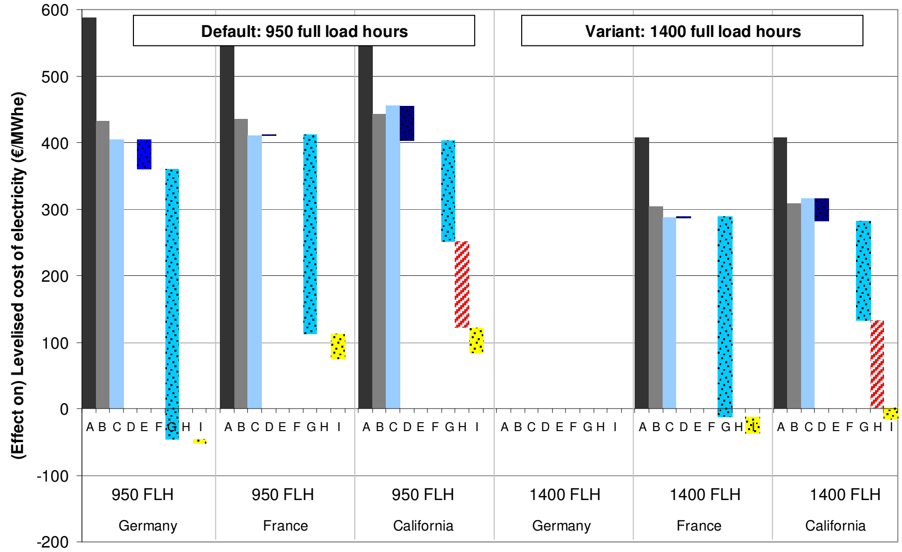


Figure 5-7 Levelised cost of electricity and effect of support schemes for solar photovoltaic energy (**default, 950 full load hours** and **variant, 1400 full load hours**)

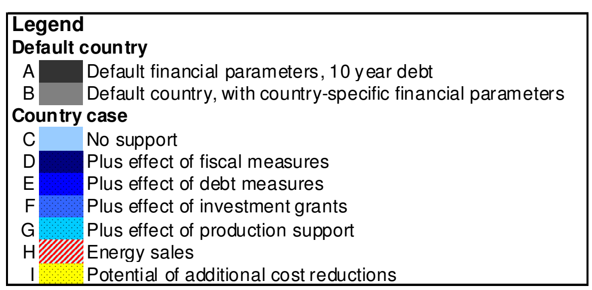


Figure 5-7 shows the results for the assessment for solar photovoltaic open space installations for both the default (950 full load hours, FLH) and variant (1400 FLH) case (2006 situation).

<u>Overall economic viability</u>

The figure clearly shows that solar-PV projects in Germany are economically viable in the 950 FLH default case (which is representative for many sites in Germany), whereas projects in France and California only become viable in the higher 1400 FLH variant case (which is more representative for those countries). Both the German and French feed-in tariffs are independent of solar irradiation, but as indicated, French projects are only feasible with higher annual solar irradiation. The break-even point for France lies at about 1350 FLH. The feed-in premium in California results in overall levelised cost of electricity close to the end-user price of electricity (about 2 €/MWhe lower).

Effect of support instruments

The reductions in the levelised cost of electricity as compared to the default country are 30% (Germany, France) and about 22% (California). This is a consequence of the design (feed-in vs. feed-in premium) and period (20 year in Germany and France, 5 year in California) of the main support scheme.

Again, fiscal and debt measures have an important contribution in reducing the levelised cost of solar-photovoltaic projects, but the main component is either feed-in tariff or premium.

Financial resources

The debt/equity ratio resulting in the lowest levelised cost of electricity is for Germany and France about 80/20%, and for California 70/30%, resulting in a slightly higher overall leveleised cost of electricity.

The 500 kW project with an investment of 1.75 M€ requires annual revenues of about 0.2 M€. The financial resources for this project are shown in Figure 5-8. California has a significant contribution from both state and federal government budgets. The support scheme is typically designed for relatively small projects, integrated in the facilities or houses of the end-users, with the intention to reduce end-use consumption (notably during peak hours). For this a government funded programme may be a suitable way to introduce this technology in a short period of time.

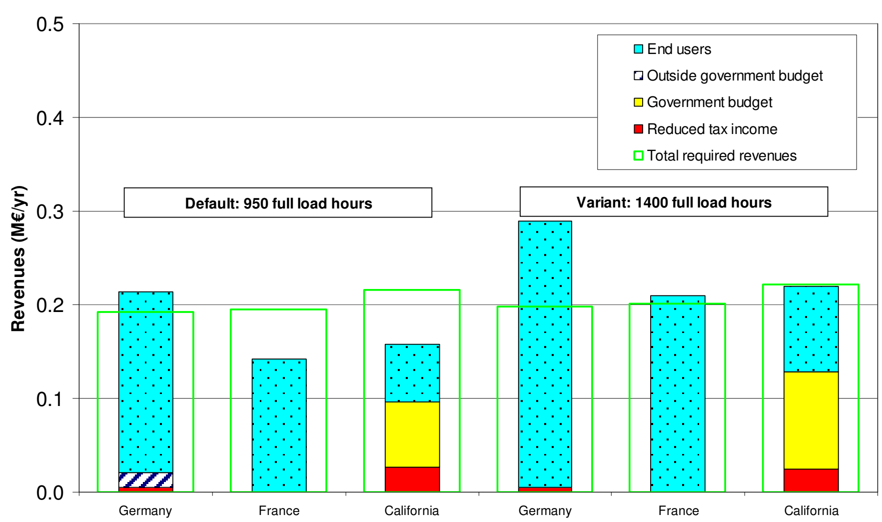


Figure 5-8 Financial resources for the 0.5 MW solar-photovoltaic energy case (**950 and 1400 full load hours**)

5.5 Solid biomass co-generation (10 MW_e and 26 MW_{th})

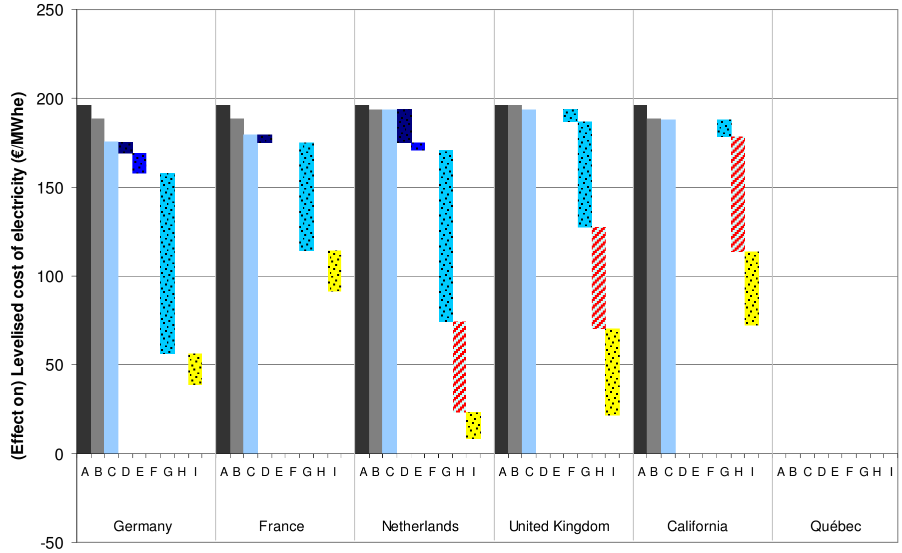


Figure 5-9 Levelised cost of electricity and effect of support schemes for solid biomass co-generation (**default, 4000 FLH**)

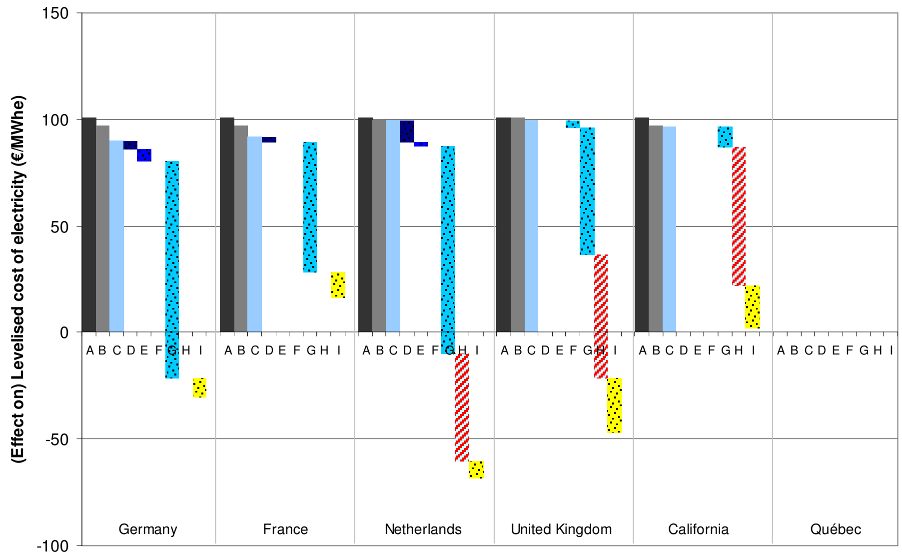


Figure 5-10 Levelised cost of electricity and effect of support schemes for solid biomass co-generation (**variant, 7500 FLH**)

Legend

Default country

- A Default financial parameters, 10 year debt
- B Default country, with country-specific financial parameters

Country case

- C No support
- D Plus effect of fiscal measures
- E Plus effect of debt measures
- F Plus effect of investment grants
- G Plus effect of production support
- H Energy sales
- I Potential of additional cost reductions

Figure 5-9 and Figure 5-10 show the results for the assessment for the solid biomass co-generation project (10 MWe and 26 MWth) for both the default (4000 FLH) and variant (7500 FLH) case for the year 2006.

<u>Overall economic viability</u>
The figures show that the biomass-CHP cases are only economically viable for some countries in the high-FLH variant case (with the technical and economic assumptions presented in Table 4-3 and Table 5-1). The 4000 FLH case (typically used for heating during autumn and winter), is only viable at negative fuel costs (e.g. –0.5 €/GJ for the German case, as compared to the 3 €/GJ used in the current cases), which would imply that the fuel is actually a waste product for which treatment costs could be charged. Fuel cost can be higher if actual heat prices are higher than assumed here (5.5 €/GJ).

The 7500 FLH variant case (typically located near an (industrial) unit with a more or less constant annual heat demand) would be viable in Germany, the Netherlands and the United Kingdom. The break-even point for the German case would be at either 6000 full load hours or about 4.5 €/GJ biomass fuel cost. For France the break-even point would be at about 1 €/GJ fuel cost. Both Germany and France incorporate co-generation in the determination of the level of the feed-in tariff: 20 €/MWhe for Germany and a maximum of 12 €/MWhe in France. The German feed-in scheme further makes a distinction between different biomass resource and conversion technologies and also provides a premium for innovative technologies.

The Dutch premium scheme is based on the assumption that biomass co-generation will not be applied in the Netherlands. It hence results in an over-support for the current case. Without heat production and a 30% electrical efficiency, the levelised cost would increase from about -10 to 35 €/MWhe, which would make the project still economically viable at electricity contract prices of about 50 €/MWhe (where 32 €/MWhe was the original assumption for the cost calculations).

In the UK the biomass cases are assumed to be eligible for an investment subsidy of 1.4 M€ (total investment 32.5 M€). The overall effect on the levelised cost of electricity is about 3.5 €/MWhe. The effect of the market price of ROC and LEC in combination with the market price for 'grey' electricity makes the 7500 FLH case a viable one.

In California the Market Price Referents are not sufficient to support these particular cases. The 7500 FLH variant case is economically viable at fuel costs below 1.5 €/GJ. The production tax credit reduces levelised cost by almost 10 €/MWhe.

Effect of key financial parameters

Biomass projects have relative high risks due to the dependency on fuels. If fuel supply is hampered by logistical problems, or if fuel prices increase, the continuation of the project might be endangered. Furthermore, it might be hard to negotiate long-term (>5 year) supply contracts if the project depends on purchased fuels. Current price levels for biomass fuels that can be compared with forestry residues range from 1.5 to 4 €/GJ, but are expected to increase in the coming years to levels above 5 €/GJ as a consequence of the high demand for biofuels.

The debt conditions reflect this risk, notably by applying higher debt service coverage ratios and lower debt terms. The investor will also use shorter economic lifetimes, typically 10 year for most countries (except for instance for Germany and France, with main support schemes stretching over 20 and 15 years, respectively). Hence, as compared to the default country case, reductions in levelised cost of electricity are relative small: about 10% for Germany and France, 1% for the Netherlands and the United Kingdom, and 4% for California.

Effect of support instruments

Fiscal and debt measures have similar effects as been discussed for onshore wind energy and will not be discussed in detail here again. Both types of measures typically concern the investment in the technology (except for the Production Tax Credit in the US).

Only the United Kingdom has an investment subsidy for biomass co-generation See above), with an overall reduction of the levelised cost of electricity of 3.5 €/MWhe for the 7500 FLH case.

None of the schemes has investment grants for onshore wind energy. Several countries have used this instrument in the past in the early days of wind energy deployment. The investment tax deduction in the Netherlands, implicitly acts as a kind of conditional investment grant. When the project is a generating income, the investment can be partially deducted from this income, and is typically used to repay part of the debt.

As for all technologies discussed before, the production support schemes have the most prominent contribution in reducing the levelised cost of electricity. Next to the particular level of support, the period of support is crucial for the risk perception by the market, as discussed above. If the German 20 year feed-in support of 101.5 €/MWhe would be replaced by a 10 year support of 135 €/MWhe (which at a RoE of 12% would generate the same net present value for the investor), the overall levelised cost of electricity would increase by about 10 €/MWhe.

Potential of additional cost reductions

For all countries additional cost reductions could be achieved (ranging from about 7 to 26 €/MWhe for the 7500 FLH case). A stable RES policy and support scheme periods that are close to the technical lifetime of the project help to reduce costs. The continuous discussion on the sustainability of various biomass conversion routes (notably held in Europe for instance on palm oil) has forced several projects to look for new biomass resources. Clarity in that respect can reduce regulatory risk significantly and can contribute to the creation of a (large) sustainable market for biofuels.

But bio-energy has some additional project risks that are more difficult to address by policies and measure: the fuel supply and fuel price risk. The creation of larger biomass markets can help to reduce these risks and/or to make future changes in supply and demand more predictable. Another option could be to combine biomass storage and logistics of multiple projects. This could reduce the minimum debt service coverage ratio or the biomass reserve of individual projects, as required by lenders.

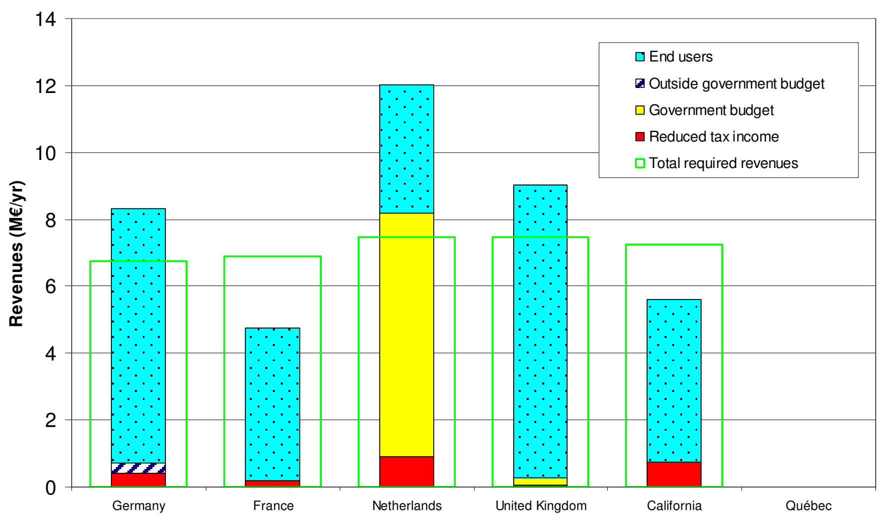


Figure 5-11 Financial resources for the 10 MWe/26 MWth solid biomass co-generation (**7500 full load hours**)

Financial resources

The biomass co-generation project requires an investment of 32.5 M€. The model calculations result in debt/equity ratios of 70/30% to 60/40% for most countries. For the Netherlands this is slightly higher (75/25%) as a combined effect of the investment tax deduction and the low-interest Green Fund. The project would in

California result in a 42% equity share (with the Production Tax Credit not affecting the debt/equity ratio).

Figure 5-11shows the origin of the revenues for the 10 MWe / 26 MWth biomass co-generation plant. Annual revenues ranging from 6.7 to 7.5 M€ are required. Again the Netherlands show a large impact on government budgets (note that the Dutch scheme was not designed fo biomass co-generation and assumed lower electricity market prices).

From the above some specific conclusions can be drawn for bio-energy support schemes: For schemes that are based on feed-in tariffs or feed-in premiums, the correct calculation of levelised cost of electricity is elementary. Most of these schemes aim to provide enough incentives to invest in these RES-E technologies, but want to prevent over-support. For this the type of biomass used (as for instance applied in Germany), the capacity class of the conversion unit (Germany, Netherlands), and the overall conversion efficiency (France) needs to be incorporated. As fuel prices are expected to increase with grower demand, frequent adjustment may be required and the system should allow for these modifications.

6 Conclusions and recommendations

6.1 Long-term commitment

- A favourable generic and RES-specific investment climate can result in levelised cost savings ranging from 10-30% in selected cases. These savings can be attributed to reductions in the cost of capital.
- Policies and measures and associated support schemes that anticipate on the risk perception by investors and lenders, have lowest costs of capital. In designing support schemes, the expertise of the financial sector should be involved.

Reducing actual and perceived risks for market actors results in lower financing costs for renewable energy technologies. As discussed in chapter 2, these risks are notably high for the project development phase and operation phase of renewable energy projects. These risks are or can be susceptible for (changes in) generic and RES-specific policies and measures. So what is the recipe for a good policy that effectively reduces cost of capital, and hence levelised cost of electricity and required additional financial (government) support?

Too often the debate is restricted to a discussion on the benefits and drawbacks of feed-in tariffs schemes vs. feed-in premium schemes vs. obligation schemes vs. tendering schemes. We plea for a more comprehensive approach, that incorporates the full spectrum of support instruments applied in different policy contexts, as illustrated by the example given in the text box on the next page.

The example shows that before looking at the exact design of the various elements in the support scheme, a clear political and societal long-term commitment towards renewable energy is required. Based on this, a stable and reliable support mechanism can be designed, that effectively meets the policy goal, at acceptable levels of investor risk, and at acceptable social costs. Commitment, stability, reliability and predictability are all elements that increase confidence of market actors, reduce regulatory risks, and hence significantly reduce cost of capital and overall societal cost. A proper translation of this commitment in the design and timeframe of the support instruments, is the key challenge in this respect. In the previous chapter we have shown that the effect can be significant: reductions in levelised cost of electricity can be achieved ranging from 10 to 30% as compared to a default country that has no particular RES policies in place.

Offshore wind energy in Germany and the Netherlands

The success of the German support for renewable energy is more than just the feed-in tariff. Until recently the German feed-in tariff was not sufficient to make offshore wind energy economically viable. As a consequence no (remote) large offshore wind projects were commissioned. In the Netherlands two offshore wind projects are in operation, established with sufficient financial support, but after quite long lead times. So, at first sight, the Dutch scheme has been more effective. However, a project developer with exclusive rights for a wind project in the German part of the Continental Shelf can sell its project at a good price, whereas projects at the Dutch part are currently hard - if not impossible - to sell. The difference is the commitment of the German government as perceived by market actors. They see the German government pro-actively removing barriers and are confident that feed-in tariffs will be adjusted to a viable level. In the Netherlands, they have seen many changes in the design and levels of support (with a 0 €/MWhe feed-in premium since 2005), and many institutional and regulatory barriers that restrict the further deployment of offshore wind energy.

In this report we have used a quantitative cash flow analysis to assess the effect of various design elements on the levelised cost of electricity of several country / technology cases, which are project financed (2006 situation). The impact of different financial parameters on this levelised cost was assessed, based on the more qualitative information provided in the country characterisations. Here we will summarise and conclude on several of these design elements.

6.2 Removing risk by removing barriers

- Policies that improve the success rate of the project development phase will reduce the project investment and hence levelised energy costs of renewable energy technologies. This refers to amongst others:
    - Improving permitting procedures (e.g. pre-planning, streamlining and simplification of procedures, one-stop agencies, maximum response periods)
    - Improving grid connection procedures (e.g. technical and operational standards, transparent procedures, non-discriminatory access)
- A stable and predictable long-term policy context will contribute to this improved success rate and reduce both investment cost and cost of capital.

The overall effect on the cost of capital of removing barriers is hard to quantify. The direct effect on the levelised cost of electricity can be in the range of 5 to 10% due to increased project cost. But a poor development climate will also result in a higher required return on equity, which could result in an increase in levelised cost of the same order of magnitude.

With detailed renewable energy resource data (notably relevant for on- and offshore wind energy), projects can be financed at more favourable loan conditions, e.g. lower interest rates (several percent points) and debt service coverage ratios (e.g. from 1.4 to 1.3). Governments can invest or participate in data acquisition (similar to practices common in oil and natural gas exploration), which will reduce overall levelised cost of electricity (e.g. several percent for offshore wind energy). In tendering procedures this will significantly reduce the overall costs of that process, to be borne by all project developers, while only benefitting a few.

The various actions that can be taken to remove existing barriers were not addressed in this report in detail, but are summarised in section 3.1. They are often country and technology specific and are already extensively described in reports for other IEA Implementing Agreements and for the European Commission[1].

6.3 Removing risk by sharing risk

The deployment of renewable energy technologies still requires policy support, both in terms of removal of institutional barriers and in providing support to make these technologies economically viable. This makes renewables susceptible for changes in policies, especially when the cost of the policy instruments are financed via the government budget. For some countries market actors consider these regulatory risks to be high, resulting in relative high cost of capital.

Governments or government-related entities can reduce the cost of capital by directly removing part of this risk from the project. Here some examples are given, but risk sharing is also an important element in the subsequent sections:

Loan guarantee programmes

As presented in section 3.5 government loan guarantees can be important in reducing the cost of capital for renewables. The option is not encountered in the country cases, but has proven to be successful in other areas. By underwriting all or part of the debt for a project, lenders have significant lower risk in case of default or underperformance of the project. This risk reduction is translated in lower interest rates (e.g. 1-2%, resulting in reductions upto 5-10% in the levelised cost of electricity), but potentially also in longer debt terms and more favourable debt service requirements with even higher reductions in the cost of capital. One can even consider to prescribe these favourable debt conditions (e.g. 20 year debt term) in order to receive a loan guarantee.

If properly designed and managed, the societal or government cost of a loan guarantee programme is marginal, or even positive, due to the lower financial

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[1] E.g. IEA Wind Energy (2006), IEA PVPS (2007), IEA Bioenergy (2007), OPTRES (2007)

support needs for renewable energy. The loan guarantee fund can be financed via government loans (with typically low interest rates) or via insurance premiums to be paid by the projects[2].

Project participation

The government can also act as equity provider by participating in renewable energy projects, directly or indirectly via government bodies. Doing so, a clear signal is given to other investors and lenders that the government is committed to the deployment of renewable energy and that regulatory risk will be addressed and reduced. In oil and natural gas exploration and exploitation these kind of government participation models are common, generating income to the government. Government participation has several benefits:

- it in effect and effectively removes part of the project risk from conventional investors and lenders;
- as government bodies can loan at lower interest rates (down to 2%, with significant securities in place), they can be satisfied with a lower return on equity resulting in a lower cost of capital for the project;
- the participation will generate income to the government;
- participation will provide feedback on the economics and implementation barriers of large renewable energy projects and enables the government to adjust its policies with a better understanding of markets; and
- the attitude that can be summarised as ‘practice what you preach’ or ‘put your money where your mouth is’, results in a lower risk perception by market actors and hence lower cost of capital.

The effect of this model on the government budget will be positive when properly designed and managed: With cost of capital being reduced, the cost of renewable electricity and required level of support will be lower, resulting in lower societal and/or government cost. At the same time the participation activities will generate income.

Government participation was not encountered in the country cases of this report, but in analogy to the experience in the oil and natural gas sector, this model could be applied to the renewable energy sector. Due to transaction costs, it is envisaged that notably large-scale projects should be eligible. Notably projects that are affected by several risk classes (e.g. project level risk, regulatory risk, and market risk), would benefit from this participation model.

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[2] Harris and Navarro (1999)

Investing in infrastructure

By making the transmission system operator (TSO) responsible for the grid connection of the offshore wind energy projects, both project cost and cost of capital can be reduced. The TSO will finance the project on its own balance sheet or will have access to cheap loans under favourable conditions. Levelised cost of electricity can be reduced by more than 15%, of which roughly 5% as a direct consequence of the reduced cost of capital. Also investment costs can be reduced: several wind projects could be jointly connected to one offshore grid, or wind energy projects could be combined with offshore electricity production from natural gas. These additional cost savings are estimated to be in the order of 5% or more, due to the higher utilisation rates of the offshore grid.

Share or remove market risks

The first tender round for onshore wind energy in Québec incorporated a mechanism to correct for inflation, and changes in currency exchange rates and steel prices. Doing so, the risk of price changes was not to be carried by the project consortium, but by the utility that would purchase the electricity after commissioning of the project. The effect is twofold: the market risk premium can be significantly reduced, and the utility has more certainty that projects will actually be developed.

6.4 Investment subsidies

In the country cases one example of investment subsidies was encountered for biomass co-generation in the UK. In this particular example, the overall effect on the levelised cost of electricity is relatively small. An important effect of investment subsidies is the attention they give to certain technologies. Furthermore, they remove part of the risk to the equity provider (see previous paragraph) and reduce the amount of (higher cost) equity. In general, investment subsidies are believed to be more effective at the demonstration and market introduction phase, than during the deployment phase with a larger emphasis on stimulating production of renewable energy. Investment grants could be converted in equity (government participation) or debt after successful commissioning of a project. Doing so the effect on the government budget can be kept to a minimum.

6.5 Debt measures

Policies that anticipate on risk assessment practices by lenders can reduce costs of capital significantly:

- Create market conditions and design support schemes that result in debt terms being close to technical lifetimes (e.g. longer duration of production support and power purchase agreements (PPAs)).
- Take measures that result in lower interest rates, e.g.:
  - offer low (state bank) interest rates
  - offer tax deductions for investments in renewable energy funds
  - facilitate the collection and disclosure of site-specific resource and other relevant data, such as meteorological, geological or bathymetric data (e.g. wind, solar, wave and tidal energy resource)
- Facilitate the demonstration of new technologies that will result in improved knowledge on the risk profiles of these technologies and hence reduce the debt service requirements and required return on equity for future projects.

Low-interest loans

In the country cases the following instruments where addressed: *low-interest government loans* (e.g. from state banks in Germany) and *low-interest loans from green funds* (via tax-free bonds, e.g. in the Netherlands). The latter category is in effect a tax deduction for investors in capital funds that provide loans to renewable energy projects. The discount on the interest rate is typically in the range of 1-2%, depending on the fiscal system. As illustrated for several country and technology cases the direct overall effect of these kind of debt schemes is upto 5-10% on levelised cost of electricity. But indirectly they can affect other key financial parameters used by investors and other lenders, such as the economic lifetime, debt term and debt service conditions. The KfW Umwelt Program (which is restricted to 10 M€ per project) in Germany has a maturity of 20 years. Together with the 20 year term of the feed-in scheme this results in a longer economic lifetime used by the investor and hence a lower cost of electricity. By offering a redemption free period (e.g. of 3 year) a reduction in the cost at the beginning of the operation phase can be achieved. This effect is missing in the green fund scheme, where the design of the debt scheme is determined by market actors.

The effect of low-interest government loans on government budgets is limited, as they can be kept outside these budgets. Administrative costs can be kept at reasonable levels. For tax-free bonds the government will be faced with a reduction in the tax income (equalling upto 5-10% of the levelised cost of electricity). This makes this policy instrument more susceptible to changes in policies.

As discussed in section 6.3, loan guarantee programmes can have similar direct and indirect effects.

6.6 Fiscal measures

- General or RES-specific fiscal policies that allow for flexibility in fiscal depreciation, can reduce the levelised cost of renewable energy.
- Short fiscal depreciation terms and/or schemes with large initial depreciation of assets have the highest cost reductions.
- Flexibility in terms of tax loss carry-back or -forward should be offered to RES projects.

In this report the following fiscal measures were encountered: *tax-free bonds* (discussed in the previous section), *investment tax deduction* (Netherlands), *production tax credit* (PTC, in the US), and *flexible/accelerated depreciation* schemes (US, Canada). All fiscal measures are directly affecting tax income and hence are susceptible for changes in policies (albeit that in the political arena a reduced tax income is not as visible as increased government expenses). For instance, the stop-and-go situation of the PTC in the US has had a direct impact on the deployment of wind energy in the US. Fiscal measures require from the project financing perspective (an often significant) net positive income to fully benefit from the offered tax deduction potential. This may result in more or less complex legal and financial structures, that are set up to reap these benefits. This adds to the transaction cost of the project and could be considered as a cost of capital.

Investment tax deduction

The investment tax deduction can have a significant effect on the levelised cost of electricity, upto 10% as shown for the cases in the Netherlands. The investment tax deduction in the Netherlands implicitly acts as a kind of conditional investment grant. When the project is generating income, the investment can be partially deducted from this income, and is typically used to repay part of the debt. The benefit to the project is usually somewhat smaller than the direct tax deduction effect. For larger projects complex legal/financial structures have been set up in the past in order to reap the tax benefits. The annual budget for the tax deduction scheme is determined each year. In the UK a first-year 40% capital allowance is given for small and medium enterprises, which typically could benefit renewable energy production special purpose companies. Solar-PV receives a 30% investment tax credit in the US.

As with investment subsidies, the investment tax deduction does not necessarily result in a higher or more efficient production of renewable energy. For this reason it should be supplementary to other production support instruments.

Production tax credit

The production tax credit in the US is an example of tax deductions related to renewable energy production. The investor can deduct 19 US$ from his taxable income for each produced MWh of electricity and a period of 10 years. As already addressed, the investor may not always be capable to fully utilise this tax credit. Another important factor is that the credit only benefits the investor (and not the project), typically resulting in higher equity shares. The cost of capital would be lower if the 19 US$/MWhe would be offered as a direct production incentive. For the 2500 FLH onshore wind energy case in California, the equity share would be reduced from 34% to 19% in our default model calculations, with a reduction in the levelised cost of electricity of 61 €/MWhe by about 1%.

Flexible/accelerated depreciation schemes

Both the US and Canada have implemented accelerated depreciation schemes as support instrument for specific renewable energy technologies. Accelerated depreciation results in larger tax deductions in the first years of operation, whith the highest net rpesent value for the investor. In the US onshore wind energy can be depreciated in 5 years (5 year Modified Accelerated Cost Recovery System (MACRS) at the federal level, but 150% declining balance for the state tax in California). Canada has a 20 year, 50% accelerated declining balance scheme as compared to the conventional 6% (in 2006) declining balance scheme. The effect on the levelised cost of electricity is 1% (California) to 4% (Canada) for the cases discussed in this report. However, if we assume that in the Californian case all tax benefits of the MACRS could be transferred to parties with sufficient opportunities for tax deduction, the levelised cost would be reduced by upto 10-15%. For instance, the 2500 FLH onshore wind energy case would see its levelised cost being reduced from 61 to 53 €/MWhe, with a 7 €/MWhe direct contribution from the MACRS.

The UK has an enhanced capital allowance for certified co-generation projects. The tax benefits of the 100% first-year ECA can not be carried forward to subsequent years, which makes it not interesting for a real project financing case without any provisions to deduct negative EBT (earnings before taxes) from other taxable income. This measure is hence more favourable for corporate financing and was not incorporated in the analysis for this study.

In the past the Netherlands had a flexible depreciation scheme, which offered investors an elegant tool to minimise their corporate taxes.

Other fiscal measures

Other fiscal measures include tax-free bonds (as discussed in section 6.5) and various other tax exemptions, such as sales tax or local property tax exemptions. They can be used to reduce the up-front cost of a project, upto percentages of several tens (depending on the specific fiscal regimes), implicitly acting as an investment subsidy.[2]

6.7 Production support

Feed-in tariff (FIT) and -premium (FIP) schemes
The most important element of FIP and FIT schemes is that they fully (FIT) or partially (FIP) remove the market risks of a project during a fixed period of time. The longer this period of guaranteed prices, the lower the cost of capital. Because of this, FIT/FIP have in general a relatively large debt schare. For the technologies considered in this report (on- and offshore wind energy, solar photovoltaic energy and biomass co-generation) a timeframe of 15 to 20 years is preferred. In feed-in premium schemes the risk of variations in electricity market prices is reflected by a premium in the tariff in the purchase power agreement. It may be hard to acquire a PPA with the same 15 to 20 year tenure at reasonable risk premium levels.

Other production incentives: In some schemes a certain production incentive is given for each unit of renewable electricity produced over a given period of time (e.g. 10 CAN$/MWh over 10 year, in the EcoENERGY for Renewable Power in Canada). This production incentive is not intended to fully bridge the gap between electricity market prices and the price of renewable electricity, but apart from generating additional revenues, it contributes to removing part of the market risks for a project.

If other support instruments are aligned with the design of the production support (e.g. same period of support as the debt terms in low-interest government loans), the effect on key financial parameters will be enhanced. Some FIT schemes (Germany, France) have both a high initial and lower basic feed-in tariff. The high initial tariff provides in a front loading of the payment stream, resulting in lower levelised cost of electricity. For instance, if the 3500 FLH offshore wind energy case for Germany would receive a fixed tariff over 20 year (instead of a higher initial tariff for the first 12.8 year) with the same net present value to the investor, levelised cost would increase by more than 1%.

It should be borne in mind that a proper policy design encompasses more than just reducing risks. In many FIT/FIP and other production incentive schemes, special attention is given to prevent over-support of renewable energy production (see section 3.2). The country cases in this report showed examples of the use of technology and project-specific feed-in tariffs or -premiums, and the possibility to correct for changes in market price developments. This does not have to affect the cost of capital, when properly applied and in a stable policy context.

Tendering schemes
The tendering schemes discussed in this report (Québec, California) all result in guaranteed project-specific contract prices for a specific period of time. The tendering process is used to let the market determine what the required level of support should be. After winning the tender, a project developer has certainty about his operating income and can use and negotiate favourable financing terms. The project development phase has higher risks, as not all bids will be successful. (See also section 6.3 for the Québec case).

Obligation schemes
The cost of capital will generally be higher for obligation schemes due to both higher market risks and perceived regulatory risks. The certificate market - by its design - can not offer a fixed price directly as is the case in FIT/FIP schemes. Furthermore, the level and timeframe of the obligation as well as other key design parameters (e.g. penalties, issuing of certificates), are set by government policies and hence susceptible to policy changes. This results in lower contract periods in the PPA, lower debt terms and higher debt reserve conditions, or, in other words, in a higher levelised cost of electricity. The comparative assessment in chapter 5 showed that the levelised cost of electricity in the UK (without support instruments) are the highest of all countries. However, because of the current design of the UK scheme, the UK levelised cost of electricity after incorporation of the various policy instruments shows one of the lowest and/or even negative levelised cost results. The over-support of the UK obligation scheme provides enough appetite to invest in RES-E technologies, but societal costs may be considered to be too high.

Reducing the cost of capital in quota obligation schemes can be achieved via various routes, but is not as easily done as with FIT and FIP schemes. A strong government commitment towards the scheme is essential in this respect. Changes in the scheme can seriously affect the continuity of existing projects and have to be applied with specific care. For FIT/FIP schemes this is not an issue as the FIT/FIP for existing projects is not (or: should not be) affected by new policies. Increasing the economic lifetime, the contract period in the PPA, and the debt maturity will reduce the cost of capital. This could be achieved via the instruments discussed above: by setting favourable conditions in loan guarantees, (low-interest) government loans and/or government participation. The government can also oblige obligated parties to offer long-term contracts. This will be reflected in a risk premium, but – provided that a competitive market is functioning – this premium can be minimised. The main advantage is that the financing cost will be reduced due to the increased security.

The production tax credit is discussed in section 6.6 above.

6.8 General observations

- Policies that reduce the required return on equity by investors potentially have significant cost reduction implications.
- Improved design of existing policy support schemes may be more effective in this respect, than a switch to a different policy scheme.
- Reducing the required return on equity encompasses a wide range of measures that create stability and predictability of markets, amongst others:
    - long-term and sufficiently ambitious targets should be set
    - the policy instrument should remain active long enough to provide stable planning horizons and for a given project, the support scheme should not change during its lifetime
    - stop-and go policies are not suitable and a country's 'track record' in RES policies probably influences perceived stability very much

Based on an indepth characterisation of the policy context and support instruments of each country, several interviews with financial experts in the renewable energy arena, insight in project plans for projects in different countries, the scarce public literature sources, and an own assessment of the risk situation, assumptions were made for each country/technology combination on key financial parameters (return on equity, debt service conditions). The cash flow model calculates the lowest levelised cost of electricity and related equity share. Where possible this has been validated with examples of real project cases. From this the Weighted Average Cost of Capital (WACC) can be calculated, which is shown in Table 6-1 for some of the country/technology combinations that were assessed in this report.

Table 6-1 Weighted average cost of capital (WACC) for selected combinations of countries/regions and technologies in 2006 (with all policy instruments incorporated)

Country	Renewable energy technology							
	Wind onshore		Wind offshore		Solar PV		Biomass CHP	
	FLH	WACC	FLH	WACC	FLH	WACC	FLH	WACC
Default country	2000	6.1%	3500	7.1%	950	6.0%	7500	7.7%
Germany	2000	4.5%	3500	6.3%	950	4.2%	7500	6.6%
France	2000	5.1%	3500	7.5%	1400	5.4%	7500	7.2%
Netherlands	2000	6.6%	3500	7.8%			7500	7.1%
United Kingdom	2000	6.5%	3500	7.0%			7500	7.9%
USA/California	2000	6.4%			1400	6.2%	7500	7.3%
Canada/Québec	3200	6.4%						

The table clearly shows that onshore wind energy and solar photovoltaic energy projects have low WACCs ranging from 4.5 to 6.6%, whereas the more riskfull offshore wind energy and biomass co-generation projects have WACCs ranging from 6.3 to 7.9%. The commitment towards RES, the stable policy context and the contribution of the low-interest government loan result in systematic lower WACCs for Germany. The UK and the Netherlands show higher results because of the higher uncertainties of either their scheme or their policy context.

To put the given WACCs in perspective: for investments by the energy sector in conventional energy technologies, typical values for WACCs would be about 7 to 8% for the default country, due to the lower debt/equity ratio (e.g. 60%/40% debt/equity, 12% required return on equity).

Keep the financing of the support scheme outside the government budget
The history of the stop-and-go implementation of the production tax credit in the US, and the several changes in the design and levels of the Dutch support scheme, both illustrate the importance of keeping support instruments outside the government budget. As illustrated in Figure 5-4, Figure 5-8 and Figure 5-11, the support scheme in the Netherlands has a particular high dependency on government budgets. Because of the experiences in the past, this results in higher perceived risks by market actors and hence higher cost of capital.

Consider the different financing models in the design of policy support schemes
To our knowledge this report is the first to make a comparative assessment of **all** support instruments for different technologies in different countries from a project financing perspective. With the renewable energy market developing fast, financing models can be expected to develop fast as well. This can have significant consequences for the optimal design of support instruments. As illustrated in several examples throughout the report, some fiscal facilities can not be fully utilised by projects, due to lack of taxable income. Corporate financing results in rather different levelised cost of electricity due to the lack of debt, the different cost of capital, and fiscal context. Especially for feed-in tariff and feed-in premium schemes, where the support levels have to be calculated with certain financial assumptions, a deviation from for instance the default debt/equity ratio can have significant effects.

In designing support schemes, all market actors should be involved. Especially investment funds and banks will be able to provide feedback on the risks related to the design of these instruments. On the one hand, a simple, coherent set of instruments is preferred to a (quasi-)sophisticated scheme; whereas on the other hand, detail is needed to avoid windfall profits or high societal costs of the support scheme. Finding the right balance is the key challenge of this process.

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